Q. Reference: "2022/2023 General Rate Application," Newfoundland Power, May 27, 2021.

Please provide the Annual Grant Thornton reports for the past 10 years.

A. Attachments A through J provide Grant Thornton's *Annual Financial Review of Newfoundland Power Inc.* for 2010 through 2019. The annual financial review for 2020 is currently ongoing.

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

Grant Thornton
2010 Annual Financial Review of Newfoundland Power Inc.

Grant Thornton

Board of Commissioners of Public Utilities
2010 Annual Financial Review of
Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2010 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 2010 was $875,210,000 compared to average rate base for 2010 test year of $871,585,000. The increase of $3,625,000 over test year is primarily a result of an increase in net plant investment. The Company's calculation of the return on average rate base for 2010 was 8.24% (2009 - 8.12%) compared to an approved rate of return of 8.23%. The actual rate of return was within the approved range of return on rate base of 8.05% to 8.41%. 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 2010 was $390,844,000 (2009 - $377,462,000) and return on average common equity for the year ended December 31, 2010 was 9.21% (2009 – 8.96%). The cost of common equity included in the 2010 GRA for ratemaking purposes was 9.00%. Since the Company's return on average common equity did not exceed the amount as determined by the formula by greater than 50 bps, a report was not required to be filed. The Company's common equity was calculated at 44.55% of total capital. As a result, the Company's capital structure for 2010 did not exceed the proportion of common equity deemed for ratemaking purposes in Order No. P.U. 43 (2009) to be 45%.

The actual capital expenditures (excluding capital projects carried forward from prior years) was 3.25% over budget in 2010. Capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $1,790,000 (2.45%). However, for each category of expenditure, the variances ranged from an over-budget of 30.67% to an under-budget of 46.93%. Significant variances are explained in our report.

The Company experienced a 5.82% increase in revenue from rates in 2010 as compared to 2009 and a 1.24% increase as compared to the 2010 test year. The increase can be explained by an increase in customer rates and demand in Gigawatt hours sold.

Net operating expenses in 2010 increased by $10,223,000 from 2009. The increase is primarily due to an increase in labour, intercompany charges, conservation, retirement allowances, pension and early retirement program costs and conservation demand management transfers. The increase of $2,326,000 in comparison to the 2010 test year is primarily due to an increase in labour and intercompany charges. These and other 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 2010 are unreasonable.

Non-regulated expenses, net of tax, decreased in 2010 by $223,300. This variance was largely explained by a variance of $468,100 related to the Part VI.1 tax adjustment as allocated by Fortis Inc. among its subsidiaries.

Our analysis of the Company's regulatory assets and liabilities and deferred charges indicated that all were in accordance with applicable Board Orders, with the exception of an additional $10,000 deferred relating to 2010 GRA Hearing costs over the maximum approved by the Board.

We reviewed the operation of the Pension Expense Variance Deferral Account (PEVDA) to ensure it operated in accordance with P.U. 43 (2009). Based on our review, the 2010 PEVDA included an overstatement of $70,310 which is to the benefit of rate payers. The Company has indicated that they will not be correcting this error.

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 2010 the Company met five out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Call Centre Service Level", "Trouble Call Responded to Within 2 Hours" 'All Injury/Illness Frequency Rate" and "Gross Operating Cost/Customer category. The Company excluded the impact of the March ice storm and Hurricane Igor from its reliability statistics.

Finally, the Company has developed a timeline for converting to US GAAP effective January 1, 2012. Due to the potential impact on regulatory assets and liabilities under IFRS, many Canadian utilities have opted to convert to US GAAP as opposed to IFRS. We recommend that the Board continue to follow up with the Company as its implementation plan unfolds.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2010 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 assess its reasonableness and prudence in relation to sales of power and energy and its 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 costs,
   - 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 as per P.U. 32 (2007) and P.U. 43(2009).

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to P.U. 19 (2003), P.U. 32 (2007) and P.U 43 (2009). As part of this review we will review charges to the Company related to Hurricane Igor.

5. Examine the Company's 2010 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 dated, December 31, 2005. Assess reasonableness of depreciation expense. Review with Company officials the status of its depreciation study relating to plant in service as of December 31, 2009.

7. Review Minutes of Board of Director's 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 P.U. 43 (2009).

11. Complete a review of the 2010 GRA Board Orders to assess compliance with Board directives.

12. Obtain an update of the Company's US GAAP convergence plan and its evaluation of adopting US GAAP effective January 1, 2012.

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

- inquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

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.

The financial statements of the Company for the year ended December 31, 2010 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 4, 2011. 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.

During the 2010 fiscal year the Company did not make any changes to its code of accounts.

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, 2010 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 2010 was $875,210,000 compared to forecast average rate base for 2010 test year of $871,585,000 as approved during the 2010 GRA in P.U. 43 (2009). The increase of $3,625,000 or 0.42% above test year is primarily a result of additional capital expenditures over the approved budget. The average rate base for 2009 was $848,493,000.

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 2010; 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 2010, 2010 test year and 2009 (all figures shown are averages):

(000)'s	2010	2010 Test Year	2009
Net Plant Investment			
Plant Investment	$ 1,366,106	$ 1,358,233	$ 1,312,224
Accumulated Depreciation	(573,627)	(575,233)	(550,832)
CIAC's	(29,642)	(27,417)	(27,450)
	762,837	755,455	733,942
Additions to Rate Base			
Deferred Charges	103,284	102,835	102,041
Deferred Energy Replacement Costs	192	192	575
Cost Recovery Deferral for Hearing Costs	354	350	301
Cost Recovery Deferral - Conservation	815	1,327	474
Amortization True-up Deferral	1,931	1,930	5,793
Customer Finance Programs	1,663	1,714	1,728
Weather Normalization Reserve	983	4,377	4,914
	109,222	112,725	115,826
Deductions from Rate Base			
Municipal Tax Liability	682	683	2,045
Unrecognized 2005 Unbilled Revenue	2,309	2,309	6,927
Customer Security Deposits	643	602	683
Accrued Pension Obligation	3,464	3,511	3,261
Future Income Taxes	2,957	2,867	1,741
Demand Management Incentive Account	338	-	213
Purchased Power Unit Cost Variance Reserve	224	224	670
	10,617	10,196	15,540
Average Rate Base before Allowances	861,442	857,984	834,228
Rate Base Allowances			
Materials and Supplies	4,476	4,461	4,366
Cash Working Capital	9,292	9,140	9,899
	13,768	13,601	14,265
Average Rate Base	$ 875,210	$ 871,585	$ 848,493

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 included in the 2010 rate base of $106,576,000 (2009 - $109,184,000) consists of average deferred charges of $103,284,000, deferred energy replacement costs of $192,000, cost recovery deferral for hearing costs of $354,000, cost recovery deferral for conservation costs of $815,000 and amortization true up deferral of $1,931,000.

In P.U. 13 (2009) the Board approved the creation of a Conservation Cost Deferral Account to provide for the recovery of the Company's 2009 costs related to the implementation of the Conservation Plan in 2009. There were no additions to this account in 2010. Pursuant to P.U. 43 (2009) the Board approved the amortization of the conservation costs associated with the Implementation Plan over a four year period commencing January 1, 2010.

In P.U. 43 (2009) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2010, hearing costs related to the 2010 GRA in the amount of $750,000. During 2010, the Company deferred $760,000, $10,000 higher than the approved amount, of 2010 GRA hearing costs and the related amortization for the year totaled $253,000.

In P.U. 32 (2007) the Board approved the amortization of the 2006 balance in the Degree Day Component of the Weather Normalization Reserve. Since it was determined that the balance of $6,800,000 was unlikely to reverse, the amount was to be amortized over five years. The calculation of the 2010 average rate base incorporates amortization of $1,366,000 for the non-reversing portion of the reserve (Return 17).

The Municipal Tax Liability arose due to a timing difference between the recovery and payment of municipal taxes. This account is being amortized over a three year period commencing in 2008 pursuant to P.U. 32 (2007). The calculation of the 2010 average rate base incorporates amortization of $1,364,000 related to this deferral. This liability was fully amortized at the end of 2010.

In P.U. 40 (2005) the Board ordered Newfoundland Power to deduct from rate base the average balance in the Unrecognized 2005 Unbilled Revenue Account which was $2,309,000 in 2010 (2009 - $6,927,000). This unbilled revenue balance arose as a result of the approval to adopt the accrual method of revenue recognition in 2006. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of $13,854,000 over a three year period, which commenced in 2008. The balance of the Unrecognized 2005 Unbilled Revenue was fully amortized in 2010.

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland Hydro's proposed demand and energy rate structure. This reserve mechanism is the Purchased Power Unit Cost Variance Reserve used to limit variations in the cost of purchased power associated with the demand and energy structure implemented as of January 1, 2005. In P.U. 32 (2007) the Board approved the amortization of the 2006 balance of $1,342,000 over a three year period beginning in 2008. The balance has been fully amortized as at December 31, 2010. In addition, P.U. 32 (2007) also approved the Company's proposal to discontinue the Purchased Power Unit Cost Variance Reserve Account and establish the Demand Management Incentive Account. In P.U. 7 (2011) the Board approved the disposition of the 2010 balance of the Demand Management Incentive Account of $994,000 (plus the related income tax effect of $318,000) by means of a credit to the Rate Stabilization Account as of March 31, 2011.

In P.U. 32 (2007) the Board approved the Company's adoption of the accrual method of accounting for income tax related to pension costs. The balance of the future income taxes liability related to pension costs included in the 2010 average rate base is $1,168,000. The remaining balance of the future income tax liability in the amount of $1,789,000 relates to capital assets.

The net change in the Company's average rate base from 2009 to 2010 can be summarized as follows:

(000's)	**2010**	**2009**
Average rate base - opening balance	**$ 848,493**	$ 820,876
Change in average deferred charges and deferred regulatory costs	**(2,608)**	(216)
Average change in:		
Plant in service	**53,881**	49,611
Accumulated depreciation	**(22,795)**	(22,766)
Contributions in aid of construction	**(2,191)**	(2,400)
Weather normalization reserve	**(3,931)**	(3,299)
Unrecognized 2005 unbilled revenue	**4,618**	5,914
Future income taxes	**(1,216)**	(1,149)
Other rate base components (net)	**959**	1,922
Average rate base - ending balance	**$ 875,210**	$ 848,493

In accordance with the new CICA Handbook *Section 3031 – Inventory*, the Company reclassified inventories of $4.3 million to the account *capital assets - construction materials* on the balance sheet as they are held for the development, construction, maintenance and repair of other capital assets. As at December 31, 2010, $4.8 million (2009 - $4.2 million) in construction materials were included in Plant Investment for financial reporting purposes but have been excluded from the Plant Investment component of the average rate base. Consistent with prior year's calculation, these inventories are included in the materials and supplies component of the average rate base.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2010 average rate base, with the exception of the 2010 GRA Hearing Costs, and conclude that, other than the exception noted, the average rate base included in the Company's annual report to the Board is accurate and in accordance with established practice and Board Orders. As noted, deferred GRA Hearing Costs were $10,000 higher than the approved maximum amount. We consider this difference to be immaterial.

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 2010 was 8.24% (2009 - 8.12%). 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 2010, the return on average rate base is calculated in accordance with the methodology approved in P.U. 43 (2009).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2008 to 2010 is set out in the table below.

	2010	2009	2008
Actual Return on Average Rate Base	**8.24%**	**8.12%**	8.20%
Upper End of Range set by the Board	**8.41%**	**8.55%**	8.55%
Lower End of Range set by the Board	**8.05%**	**8.19%**	8.19%

In P.U. 43 (2009) the Board approved the Company's rate of return on average rate base for 2010 of 8.23%, within a range of 8.05% to 8.41%. As noted above, the Company's actual return on average rate base for 2010 was 8.24% which was within the range set by the Board. The rate of return for 2009 fell short by 7 basis points below the lower range while 2008 was one basis point above the lower end of the range.

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 P.U. 43 (2009) the Board reconfirmed its previous position as per P.U. 32 (2007) 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 2010 as reported in Return 24 is as follows:

	2010 Average			2009	2008
		(000's)	**Percent**	Percent	Percent
Debt	$	**477,366**	**54.41%**	54.26%	54.06%
Preferred equity		**9,111**	**1.04%**	1.09%	1.15%
Common equity		**390,844**	**44.55%**	44.65%	44.79%
	$	**877,321**	**100.00%**	100.00%	100.00%

Pursuant to 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 2010 test year in Return 26 as well as an explanation of the variance in the actual embedded cost of debt from the cost forecast for the 2010 test year. The embedded cost of debt for 2010 was 7.63% which represents a 1 bp (0.01%) decrease from the 2010 test year embedded cost of debt of 7.64%.

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 Board Order P.U. 43 (2009).

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, 2010 is included on Return 27 of the annual report to the Board. The average common equity for 2010 was $390,844,000 (2009 - $377,462,000). The Company's actual return on average common equity for 2010 was 9.21% (2009 – 8.96%).

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 P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007) and P.U. 43(2009).
- recalculated the rate of return on common equity for 2010 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 43(2009).

In 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 2010 the cost of common equity per the 2010 Test Year was 9.00% (P.U. 43 (2009)). The actual return on average common equity for 2010 was 9.21% as noted above. This return was below the 50 basis point trigger and as such no special 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)	2010	2009	2008
Net income	$ 35,573	$ 33,201	$ 32,895
Income taxes	15,870	16,092	19,146
Interest on long term debt	35,850	34,547	32,334
Interest during construction	(820)	(675)	(618)
Other interest and amortization of debt discount costs	566	646	1,729
Total	$ 87,039	$ 83,811	$ 85,486
Interest on long term debt	$ 35,850	$ 34,547	$ 32,334
Other interest and amortization of debt discount costs	566	646	1,729
Total	$ 36,416	$ 35,193	$ 34,063
Interest coverage (times)	2.39	2.38	2.51

The above table shows that the interest coverage increased in 2010 over 2009 by 0.01 times. The increase over prior year is primarily due to the Company's higher pre-tax earnings.

In 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 2010 is 2.39 times.

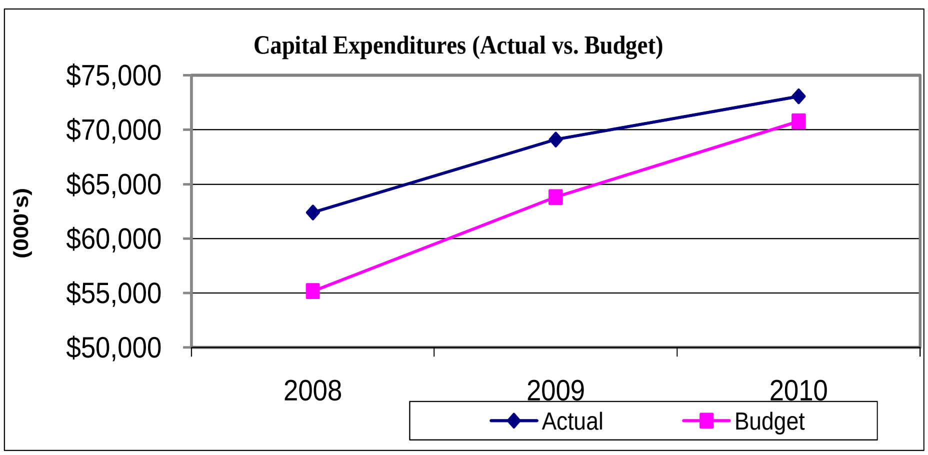
Capital Expenditures

Scope: ***Review the Company's 2010 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 2008 to 2010.

(000's)		**2008**	**2009**	**2010**
Actual	$	62,406	**69,103**	**73,082** (1)
Budget	$	55,178	**63,821**	**70,779**
Over Budget		13.10%	**8.28%**	**3.25%**

(1) Total expenditures per the 2010 Capital Budget report include the carryover amount of $2,330,000 for a total of $75,412,000. The carryover amount is made up of two projects - $900,000 relating to Substation Refurbishment and Modernization and $1,430,000 relating to rebulding transmission lines. According to the Company, these expenditures will occur in 2011.



The above graph demonstrates that from 2008 to 2010 the Company has been over budget on its capital expenditures by an average of approximately 8% and as a result the average rate base is increasing at a higher amount than forecast.

The following table provides a summary of the capital expenditure activity in 2010 as reported in the Company's *"2010 Capital Expenditure Report"*.

	Capital Budget					**Actual Expenditures**			
(000's)	**2008**	**2009**	**2010**	**Total**		**2008**	**2009**	**2010**	**Total**
2010 Capital Projects and GEC	$ -	$ -	$ 70,779	**$ 70,779**	(1)	$ -	$ -	$ 73,082	**$ 73,082**
2009 Projects carried into 2010 Western Avalon Substation – Vale Inco	-	297	-	**297**		-	-	223	**223**
2008 Projects carried into 2010 Water Street Underground Civil Infrastructure (2)	1,930	-	-	**1,930**		363	853	275	**1,491**
	1,930	297		**2,227**		363	853	498	**1,714**
	$ 1,930	$ 297	$ 70,779	**$ 73,006**		$ 363	$ 853	$ 73,580	**$ 74,796**

(1) Approved by Orders P.U. 41(2009), P.U. 17 (2010) and P.U. 35 (2010)

(2) The total original budget for the Water Street Underground Infrastructure project as noted above was $1,930,000. Total expenditures to December 31, 2010 were $1,491,000 which is $439,000 below the original budget. The Company has noted that the favorable expected variances of $439,000 on the project was due to the City of St. John's issuing a second tender on the project which resulted in lower quoted prices.

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

(000's)	2010 Budget	2010 Actuals	Variance	%
Generation - Hydro	$ 5,279	$ 4,966	$ (313)	(5.93%)
Generation - Thermal	150	196	46	30.67%
Substations	10,515 [1]	9,564 [3]	(951)	(9.04%)
Transmission	5,915	3,139 [3]	(2,776)	(46.93%)
Distribution	33,895 [1]	40,391	6,496	19.17%
General property	1,381	1,320	(61)	(4.42%)
Transportation	2,352	2,287	(65)	(2.76%)
Telecommunications	379	325	(54)	(14.25%)
Information systems	3,490	3,393	(97)	(2.78%)
Unforeseen	6,850 [2]	5,899	(951)	(13.88%)
General expenses capital	2,800	3,316	516	18.43%
Total	$ 73,006	$ 74,796	$ 1,790	2.45%

1 -Includes prior year and current year budgeted amounts as there were projects incomplete at the previous year end. The 2010 budget for Substations includes $297,000 carried forward from the 2009 budget relating to the Western Avalon Substation. The 2010 budget for Distribution includes a $1,930,000 carry forward from the 2009 budget relating to the Water Street Underground project.

2 - Includes $1,900,000 associated with Hurricane Igor approved in Order P.U. 35 (2010) and $4,200,000 associated with the March 2010 ice storm approved in Order P.U. 17 (2010).

3 - 2010 actuals include the total expense for projects carried forward from 2009. Total costs for 2010 include $223,000 relating to the Western Avalon Substation that was originally budgeted for 2009. Total costs for the Distribution category relate to the carry forward of the Water Street Underground project of which $363,000 was spent in 2008, $853,000 spent in 2009 with a further $275,000 in 2010. The balance for Substations excludes $900,000 in Substation Refurbishment & Modernization work carried over in to 2011 and the balance for Transmission excludes $1,430,000 in Rebuild Transmission Lines work carried over into 2011.

As indicated in the table, capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $1,790,000 (2.45%). However, for each category of expenditure, the variances ranged from an over-budget of 30.67% to an under-budget of 46.93%. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. In addition, the Company has noted that there is $2,330,000 related to projects that will be carried forward to 2011 relating to the Substation Refurbishment & Modernization ($900,000) and the Rebuild Transmission Lines ($1,430,000), included in Substations and Transmission respectively. The explanations provided by the Company indicate that the capital expenditure variances for 2010 were caused by a number of factors. The more significant variances noted above were as a result of the following:

Generation - Hydro

- The favorable variance of $313,000 is primarily due to a $561,000 favorable variance on the *Raise Sandy Lake Spillway to Increase Production Project.* This variance was a result of the project being deferred until 2011. Project deferral was necessary to allow time to address flooding issues affecting a neighboring property. This deferral is partially offset by an unfavorable variance of $250,000 relating to the Lookout Brook Hydro Plant Refurbishment. According to the Company, this additional cost was the result of a design change. In the original estimate, the new control room was to be located upstream, however during the detailed design it was determined that it should be located downstream of the plant to avoid the plant's septic field. This change resulted in approximately an additional $200,000 in civil work. The remaining $50,000 was due to additional mechanical work related to the cooling water system and the plant heating and cooling equipment.

Substations

- Substations had a favorable variance of $951,000. However, included in the budget is $900,000 related to Substation Refurbishment & Modernization work carried over to 2011. After adjusting for this the favorable variance is reduced to $51,000 which equates to a 0.5% in comparison to budget.

Transmission

- The favorable variance of $2,776,000 is partially due to the expenditure of approximately $1,430,000 related to the rebuild of transmission lines 23L and 24L which is being carried forward to 2011. During 2010, two major storms resulted in significant damage to transmission lines on the Avalon and Bonavista Peninsulas and the diversion of engineering and project management resources was necessary in order to reconstruct storm damaged transmission lines. After adjusting for this project, the Company has a favorable variance of $1,346,000. According to the Company, this variance includes approximately $600,000 of work not completed on transmission line 110L, which will be rescheduled for 2012, and approximately $700,000 related to deficiency correction work not completed in 2010 which will be reassessed as part of the 2011 Rebuild Transmission Lines project.

General expenses capital

- The unfavorable variance of $516,000 is primarily related to an increase in the allocated portion of pension expense. Pension expenses increased from $2,623,000 in 2009 to $7,588,000 in 2010 as a result of the amortization of 2008 losses associated with the pension plan assets along with a lower discount rate being used to determine the Company's accrued obligation under its defined benefit pension plan.

Distribution

The unfavorable variance in Distribution of $6,496,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 8,856	$ 14,616	$ 5,760	65.04%
Meters	1,239	1,872	633	51.09%
Services	2,447	4,338	1,891	77.28%
Street Lighting	1,783	2,578	795	44.59%
Transformers	7,668	6,588	(1,080)	(14.08%)
Reconstruction	3,359	3,039	(320)	(9.53%)
Rebuild distribution lines	3,632	1,268	(2,364)	(65.09%)
Relocate/Place Distribution Lines for Third Parties	685	2,363	1,678	244.96%
Distibution Reliability Initiative	447	334	(113)	(25.28%)
St John's Underground Distribution	2,480	2,381	(99)	(3.99%)
Feeder Additions for Growth	465	188	(277)	(59.57%)
Replace Mercury Vapour Street Lights	681	654	(27)	(3.96%)
AFUDC	153	172	19	12.42%
Total	$ 33,895	$ 40,391	$ 6,496	19.17%

- The unfavorable variance in "Extensions" of $5,760,000 was primarily the result of an unanticipated number of new customer connections, together with a variance in unit cost. The 2010 budget numbers were prepared based upon 3,864 new customer connections at a unit cost of $2,292. The actual number of new connections was 5,300 and the actual unit cost was $2,578. The actual unit cost was $286 or 12%, above the budgeted unit cost. The increase in unit costs is primarily due to a 20% increase in unit costs resulting from new pole contracts negotiated in 2009. This information was not available when the 2010 estimates were prepared. This amounted to an additional cost of $1,515,000 above cost. The increase in customer connections resulted in an additional expenditure of $3,291,000. There were also a number of larger extensions required to connect single customers completed in 2010. The total costs of these projects were $954,000 and include Central Waste Management (Norris Arm), Long Range Economic Development Board, Vale Inco Construction Camp, and Central Waste Management (Indian Bay).

- The unfavorable variance in "Meters" of $633,000 is due to a higher than normal number of meters requiring replacement as a result of meter testing conducted under the Electricity and Gas Inspection Act (Canada) and higher than expected customer growth. In 2010 Newfoundland Power was required to replace 7,436 more meters than forecast. Of these 7,436 additional meters, 1,436 were required to accommodate additional customer connections and the remaining 6,000 were required due to Government Retest Orders replacements and upgrades to Automatic Meter Reading meters.

- The budget for "Services" consists of expenditures required to connect new services and replace existing services. The unfavorable variance of $1,891,000 is primarily due to higher than anticipated customer growth, an increase in the unit cost relating to connection of new services and the increase in the number of existing services that required replacement. The additional customer connections resulted in an additional expenditures of $1,255,000, the 1,436 additional number of customer connections in comparison to budget contributed $744,000 of this variance and $511,000 of the variance was due to the increase in unit costs.. The unit cost increase was the result of additional overtime that was required and travel costs for employees that were brought in from other areas to assist with the connections. The expenditures for replacement of existing services were $636,000 over budget. The variance was a result of the increased number of services requiring replacement following the March Ice Storm and Hurricane Igor. The Company has indicated that this additional costs is accounted for in the Services project rather that under the Allowance for Unforeseen Items.

- The budget for "Streetlighting" consists of expenditures required for installation of new lights and replacement of existing street lights. The unfavorable variance in Street Lighting of $795,000 is primarily due to higher than anticipated customer growth and an increase in unit costs relating to installation of new lights. The 2010 budget for new Street Light installations was based on 3,864 new customer connections at an average unit cost of $286. Actual new installations were for 5,300 new customers at an average unit cost of $336. The additional 1,436 customer connections resulted in additional expenditures of $411,000 while the increase in unit costs contributed $384,000 in additional expenditures due to actual installations undertaken in 2010; according to the Company, there was an increase in the percent of street lights being fed via underground cable and duct. Customer growth on the Northeast Avalon continued to increase in 2010, mainly in new subdivisions requiring underground connection. The cost of replacing street lights was budgeted at the historical five year average of $677,000 while actual expenditures were $797,000 or $120,000 over budget.

- The favorable variance in "Transformers" of $1,080,000 is a result of fewer transformers being purchased than anticipated in the budget, as well as a small reduction in unit cost. In 2010, 1,434 units were required to serve new customers, an increase of 248 units over the three year average of 1,176. The increase was offset by a reduction in the number of rusty transformers replaced. In 2010, only 431 units were replaced versus the three year average of 821. The unit price of transformers was 4% less than budgeted.

- The favorable variance of $2,364,000 in "Rebuild Distribution Lines" is a result of less rebuild work being performed during the year. In 2010, Newfoundland Power budgeted funds to rebuild 43 distribution feeders. The amount of customer-driven work, third party and storm related work completed in 2010 was significantly higher than anticipated, resulting in less rebuilds.

- The unfavorable variance of $1,678,000 in "Relocate/Place Distribution lines for Third Parties" was driven by higher than normal system upgrade activity by telecommunications service providers. Approximately $1.45 million was spent upgrading distribution lines to accommodate third party attachments, with a portion of this amount recovered through Contributions in Aid of Construction.

Unforeseen Allowances

Based on our review, the Company's 2010 capital expenditures are in accordance with the Capital Budget Application Guidelines Policy #1900.6 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 B, the Company used the Allowance for Unforeseen Items account to expeditiously deal with events affecting the electrical system which could not wait for Board approval. There were two unforeseen events which required the use of the Allowance for Unforeseen Items account in 2010; the extreme ice storm experienced in March of 2010 and Hurricane Igor experienced in September 2010. In both instances the Company took action under the Allowance for Unforeseen Items as the expenditures were not anticipated at the time of the annual capital budget and could not be delayed until the following year due to the number of customers impacted. Capital expenditures required to respond to the unforeseen events were as follows; $4,200,000 for the March Ice Storm and $1,900,000 for Hurricane Igor. These capital requirements greatly exceeded the balance in the Allowance for Unforeseen Items account and therefore the Company sought the addition of a supplementary amount to the allowance. The supplementary amounts were approved via Board Orders P.U. 17(2010) and P.U. 35(2010). The supplementary amount was used to repair transmission and distribution lines as well as generation facilities throughout the Island portion of the Province.

- 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 8.28% in 2009 and 3.25% resulting in no additional reporting requirements.

<u>Capital Expenditure Reports</u>

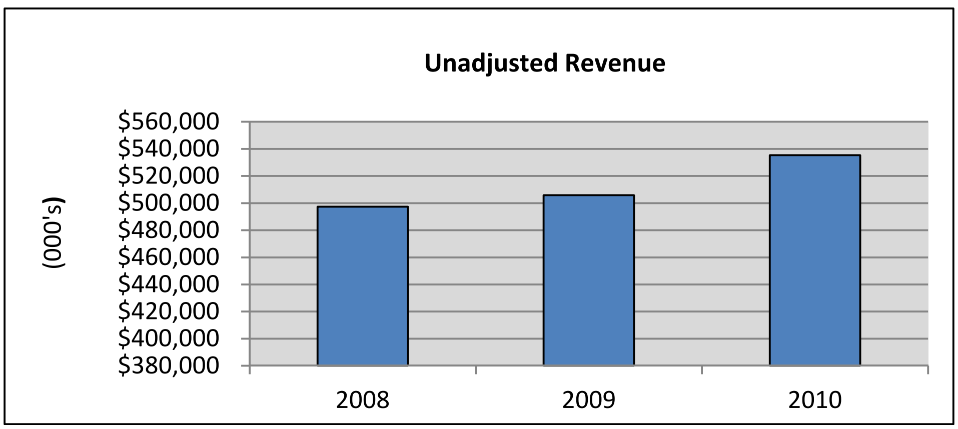
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2010 calendar year.

Revenue

Scope: ***Review the Company's 2010 revenue in comparison to test year and prior years and follow up on any significant variances.***

We have compared the actual revenues for 2008 to 2010 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2008	2009	**2010**
Residential	$ 302,916	$ 309,360	**$ 332,664**
General services			
0-10kW	11,742	11,840	**12,331**
10-100kW	63,129	63,318	**65,291**
110-1000kW	72,997	74,182	**77,976**
Over 1000kW	31,208	31,675	**31,037**
Street lighting	12,722	12,862	**13,540**
Forfeited discounts	2,646	2,644	**2,494**
Revenue from rates	$ 497,360	$ 505,881	**$ 535,333**
Year over year percentage change	4.92%	1.71%	**5.82%**



The above graph demonstrates that the Company has seen a 5.82% increase in revenue from rates in 2010 as compared to 2009. The majority of the increase is due to an increase in customer rates of 3.5%, which became effective on January 1, 2010. In addition, there was an increase in demand as Gigawatt hours sold increased by 2.3% primarily due to an increase of 1.7% in total number of customers at December 31, 2010 as compared to December 31, 2009.

The comparison by rate class of 2010 actual revenues to the 2010 test year forecast is as follows:

(000's)	Actual 2010	Test Year 2010	Variance	%
Residential	$ 332,664	$ 325,881	$ 6,783	2.08%
General service				
0-10kW	12,331	12,029	302	2.51%
10-100kW	65,291	65,650	(359)	(0.55%)
110-1000kW	77,976	76,551	1,425	1.86%
Over 1000kW	31,037	32,480	(1,443)	(4.44%)
Street lighting	13,540	13,408	132	0.98%
Forfeited discounts	2,494	2,783	(289)	(10.38%)
Total revenue from rates	$ 535,333	$ 528,782	$ 6,551	1.24%

We have also compared the 2010 test year forecast energy sales in GWh to the actual sold in 2010.

	Actual 2010	Test Year 2010	Variance	%
Residential	3,311.2	3,234.9	76.3	2.36%
General service				
0-10kW	92.5	89.7	2.8	3.12%
10-100kW	649.3	653.0	(3.7)	(0.57%)
110-1000kW	910.6	898.7	11.9	1.32%
Over 1000kW	419.2	437.6	(18.4)	(4.20%)
Street lighting	36.2	36.0	0.2	0.56%
Total energy sales	5,419.0	5,349.9	69.1	1.29%

As can be seen from the above tables, actual revenue from rates increased by $6,551,000 (1.24%) compared to the 2010 Test Year, primarily due to an increase in the average use of electricity by customers as there was a 1.29% increase in GWh sold in 2010 compared to the 2010 Test Year. The largest variance can be seen in the residential rate class where actual revenues and energy sales increased by $6,783,000 (2.08%) and 76.3 GWh (2.36%) 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.***

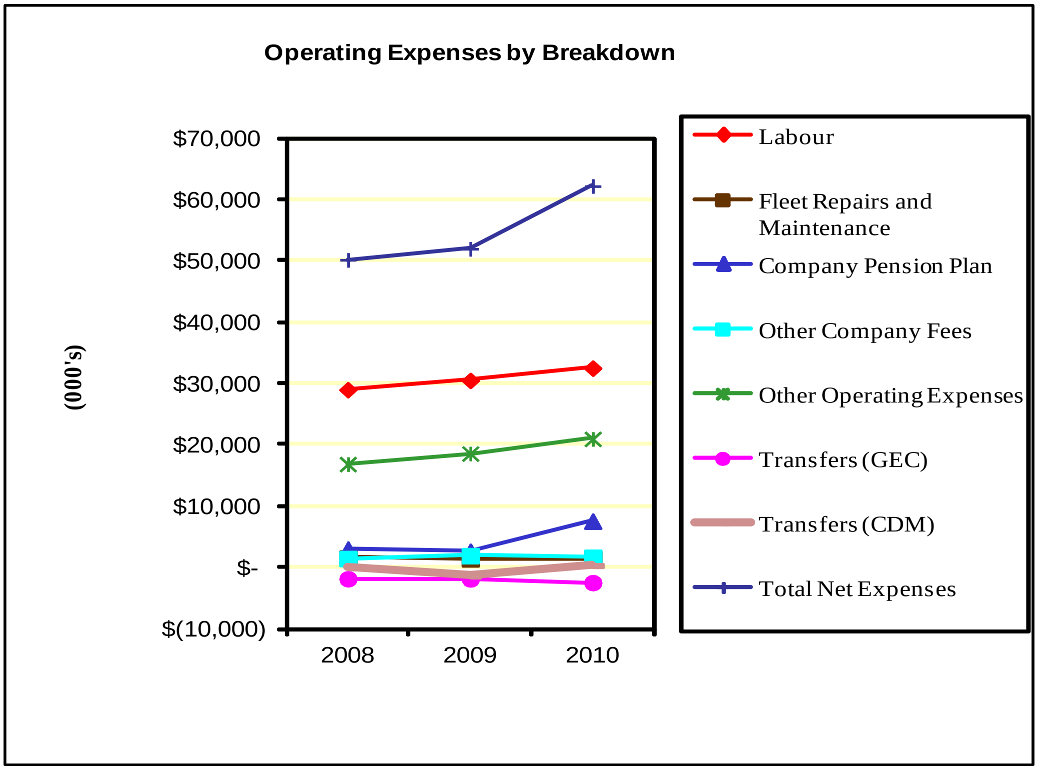
The following table provides details of operating and general expenses by "breakdown" for Actual 2010, Test Year 2010, and Actual 2009.

(000's)	**Actual 2010**	**Test Year 2010**	**Actual 2009**	**Variance Actual – Test**	**Variance 2010 - 2009**
Labor	**$ 32,531**	$ 30,749	$ 30,518	$ 1,782	$ 2,013
Vehicle expense	**1,504**	1,492	1,436	12	68
Operating materials	**1,271**	1,082	1,156	189	115
Inter-company charges	**1,043**	40	726	1,003	317
Plants, Subs, System Oper & Bldgs	**1,814**	1,952	1,907	(138)	(93)
Travel	**1,124**	1,160	1,016	(36)	108
Tools and clothing allowance	**1,139**	1,108	1,106	31	33
Miscellaneous	**1,703**	1,146	1,535	557	168
Conservation	**654**	581	306	73	348
Taxes and assessments	**706**	750	765	(44)	(59)
Uncollectible bills	**801**	963	934	(162)	(133)
Insurances	**1,094**	1,100	1,043	(6)	51
Retirement allowance	**712**	325	120	387	592
Education, training, employee fees	**246**	270	215	(24)	31
Trustee and directors' fees	**387**	394	414	(7)	(27)
Other company fees	**1,692**	1,904	1,950	(212)	(258)
Deferred regulatory costs	**453**	451	201	2	252
Stationary & copying	**299**	337	267	(38)	32
Equipment rental/maintenance	**773**	721	683	52	90
Communications	**3,009**	2,918	2,870	91	139
Advertising	**1,287**	1,431	1,079	(144)	208
Vegetation management	**1,672**	1,550	1,459	122	213
Computing equipment & software	**799**	785	801	14	(2)
Total other	**24,182**	22,460	21,989	1,722	2,193
Pension and early retirement program costs	**7,588**	8,196	2,673	(608)	4,915
Total gross expenses	**$ 64,301**	$ 61,405	$ 55,180	$ 2,896	$ 9,121
Transfers (GEC)	**(2,429)**	(1,900)	(1,836)	(529)	(593)
Transfers (CDM)	**339**	380	(1,356)	(41)	1,695
Total net expenses	**$ 62,211**	$ 59,885	$ 51,988	$ 2,326	$ 10,223

Net operating expenses in 2010 increased by $10,223,000 from 2009. The increase is primarily due to an increase in labour, intercompany charges, conservation, retirement allowances, pension and early retirement program costs and conservation demand management transfers. The increase of $2,326,000 in comparison to the 2010 test year is primarily due to an increase in labour and intercompany charges. These and other 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 2010 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 shows the trend in operating expenses by breakdown for the period 2008 to 2010.

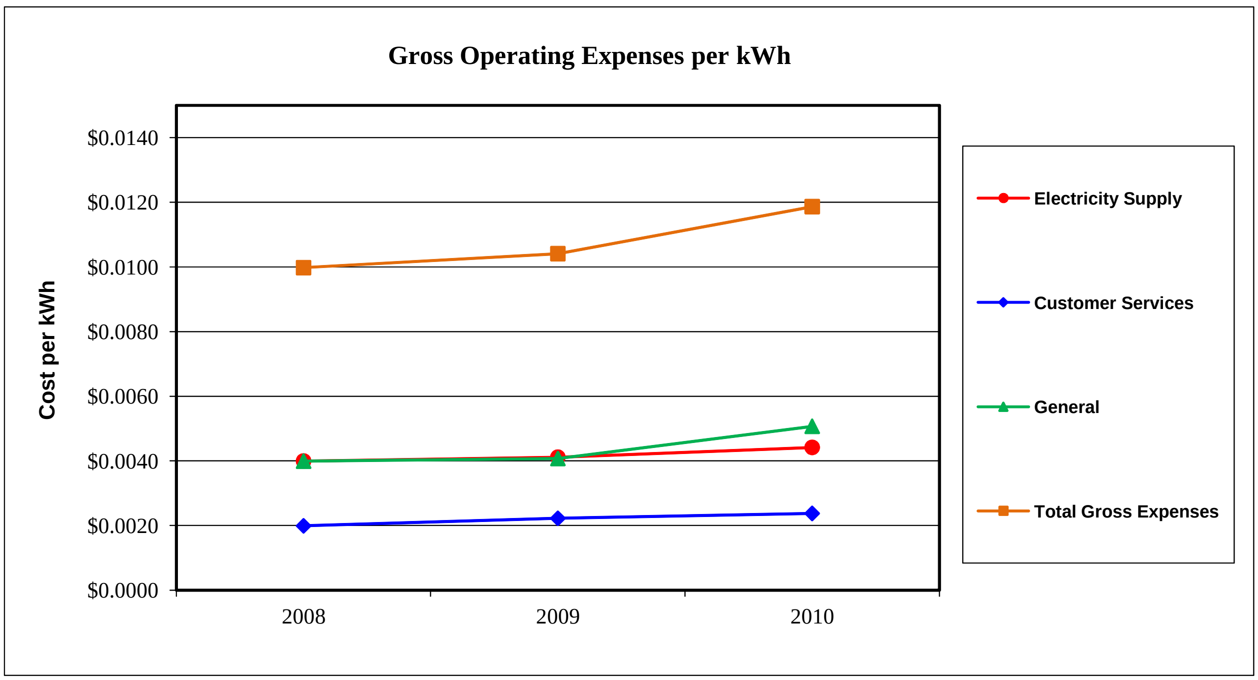
(000's)	Actual 2008	Actual 2009	Actual 2010
Labour	$ 29,013	$ 30,518	**$ 32,531**
Fleet Repairs and Maintenance	1,569	1,436	**1,504**
Company Pension Plan	3,040	2,673	**7,588**
Other Company Fees	1,468	1,950	**1,692**
Other Operating Expenses	16,879	18,603	**20,986**
Transfers (GEC)	(1,797)	(1,836)	**(2,429)**
Transfers (CDM)	-	(1,356)	**339**
Total Net Expenses	$ 50,172	$ 51,988	**$ 62,211**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2008 to 2010 is presented in the table below.

Comparison of Gross Operating Expenses to kWh Sold

		Electricity Supply		Customer Services		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
2008	5,208,200	$ 20,820	$0.0040	$ 10,363	$0.0020	$ 20,786	$0.0040	$ 51,969	$0.0100
2009	5,299,000	$ 21,810	$0.0041	$ 11,789	$0.0022	$ 21,581	$0.0041	$ 55,180	$0.0104
2010	5,419,000	$ 23,946	$0.0044	$ 12,872	$0.0024	$ 27,483	$0.0051	$ 64,301	$0.0119



The table and graph show that total gross expenses per kWh have increased by approximately 14.4% compared to 2009. This increase is largely due to the additional costs incurred during the response to Hurricane Igor and the increase in the Company Pension Plan costs.

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 2008 to 2010 is as follows:

	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Actual - Test Year	Actual 2010-2009
Executive Group	**7.0**	**8.0**	**8.0**	8.0	(1.0)	(1.0)
Corporate Office	**19.0**	**20.0**	**18.4**	18.6	(1.0)	0.6
Finance	**68.2**	**71.0**	**67.2**	66.4	(2.8)	1.0
Engineering and Operations	**408.5**	**414.0**	**407.8**	393.5	(5.5)	0.7
Customer Relations	**69.3**	**69.0**	**70.9**	64.7	0.3	(1.6)
	572.0	**582.0**	**572.3**	551.2	(10.0)	(0.3)
Temporary employees	**68.6**	**68.7**	**72.2**	77.0	(0.1)	(3.6)
Total	**640.6**	**650.7**	**644.5**	628.2	(10.1)	(3.9)
Year over year percentage change	**(0.60%)**	**(1.55%)**	2.60%	0.14%		

The overall number of FTE's in 2010 compared to 2009 decreased by 3.9. The budgeted number of FTE's in 2010 was 650.7 versus actual of 640.6. The variance between prior year and test year are the result of the following:

- The Executive Group decreased by one member as a result of a member leaving the Company.

- The Corporate Office decreased compared to 2010 Test Year as a result of an employee leaving the company, and a retirement which was offset by a new hire. The increase in comparison to 2009 relates to a new hire that started late in 2009 and would have a full year in 2010.

- Finance decreased compared to 2010 Test Year as a result of an employee on maternity leave, two employees on long term disability, and a delay in hiring a Manager.

- Engineering and Operations are below test year as a result of five retirements, four employees on long term disability, an employee on education leave, an employee on maternity leave, a deceased employee and an employee leaving the company. These results were offset by four new hires and employees transferred from Customer Relations.

- Customer Relations are below 2009 as a result of employees on long term disability and transfers to other departments.

- Temporary Employees for 2010 is below 2009 as a result of the increased use of Area Customer Representatives for call centre relief and the need for fewer temporary electricians.

An analysis of salaries and wages by type of labour and by function from 2008 to 2010 is as follows:

(000's)	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual-Test	Variance 2010-2009
Type						
Internal labour	**$ 52,601**	**$ 52,885**	**$ 50,925**	$ 47,791	$ (284)	$ 1,676
Overtime	**6,146**	**3,653**	**3,849**	3,992	$ 2,493	$ 2,297
	58,747	**56,538**	**54,774**	51,783	2,209	3,973
Contractors	**10,443**	**8,464**	**9,990**	8,329	1,979	453
	$ 69,190	**$ 65,002**	**$ 64,764**	$ 60,112	$ 4,188	$ 4,426
Function						
Operating	**$ 32,531**	**$ 31,173**	**$ 30,518**	$ 29,013	1,358	$ 2,013
Capital and miscellaneous	**36,659**	**33,829**	**34,246**	31,099	2,830	2,413
Total	**$ 69,190**	**$ 65,002**	**$ 64,764**	$ 60,112	$ 4,188	$ 4,426
Year over year percentage change	6.83%		7.74%	5.55%		
"Actual 2010" verses Test Year		6.44%				

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 2010 were $4,426,000 (6.83%) higher than 2009. Also shown, the 2010 actual labour costs totaled $4,188,000 more than the 2010 test year, representing a 6.44% increase.

Internal labour costs in 2010 were higher than 2009 by 3.29% due to normal salary increases. This was marginally offset by a reduction in the number of Full Time Equivalents and executive restructuring.

Overtime for 2010 was higher than 2009 as a result of damage caused by the March ice storm and Hurricane Igor in September. Overtime was higher than the 2010 Test Year due to the storm damage and additional work associated with customer growth.

Contractors are used to supplement the Company's work force during peak periods of construction. The increase in contract labour from 2009 and 2010 Test Year was due to storm damage partially offset by the deferral of planned work. The Company noted that a degree of flexibility is necessary for ongoing planning of capital expenditures if a reasonable degree of stability in the capital budget is to be achieved.

Operating labour for 2010 was higher than 2009 due to normal salary increases and overtime associated with Hurricane Igor in September and the March ice storm. Incremental operating labour costs to repair the damage caused by these storms is the primary reason for the increase over the 2010 Test Year.

Capital and miscellaneous labour for 2010 was higher than 2009 primarily due to normal salary increases and storm damage somewhat offset by the deferral of planned work. Capital and miscellaneous labour was higher than 2010 Test Year due to storm damage and increased customer related work.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 2008 to 2010 are included in the table below:

(000's)	Salary Cost Per FTE					
	Actual 2010	**Test Year 2010**	**Actual 2009**	**Actual 2008**	**Variance Actual-Test**	**Variance 2010-2009**
Total reported internal labour costs	**$ 52,601**	**$ 52,885**	$ 50,925	$ 47,791	$ (284)	$ 1,676
Benefit costs (net)	**(7,118)**	**(6,455)**	(6,626)	(6,027)	(663)	(492)
Other adjustments	**(554)**	**(546)**	(546)	(639)	(8)	(8)
Base salary costs	**44,929**	**45,884**	43,753	41,125	(955)	1,176
Less: executive compensation	**(1,555)**	**(1,745)**	(1,879)	(1,664)	190	324
Base salary costs (excluding executive)	**$ 43,374**	**$ 44,139**	$ 41,874	$ 39,461	$ (765)	$ 1,500
FTE's (including executive members)	640.6	650.7	644.5	628.2		
FTE's (excluding executive members)	636.6	645.7	639.5	623.2		
Average salary per FTE	70,135	70,515	$ 67,887	$ 65,464		
% increase	3.31%		3.70%	3.32%		
% decrease "Actual 2010" vs Test year	(0.54%)					
Average salary per FTE (excluding executive members)	68,133	68,358	$ 65,480	$ 63,320		
% increase	4.05%		3.41%	3.36%		
% decrease - "Actual 2010" vs Test Year	(0.33%)					

The above analysis indicates that for 2010 the rate of increase in average salary per FTE has been fairly consistent from 2008 to 2010. Average salary per FTE is also fairly consistent with the 2010 test year. The Company has noted that the 4.05% increase in average salary per FTE (excluding executive members) is primarily due to negotiated salary increases for union employees and annual increases for managerial employees.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2008 to 2010 and the targets set for 2010:

Measure	**Target 2010**	**Actual 2010**	**Actual 2009**	**Actual 2008**
Controllable Operating Costs/Customer	**$217.4**	$215.8	$206.7	$205.6
Earnings	**34.0m**	35.0m	32.6m	32.3m
Reliability - Duration of Outages (SAIDI)	**2.62**	2.59	2.50	2.70
Customer Satisfaction - % Satisfied	**89.0%**	89.3%	89.5%	89.0%
Customer Satisfaction - 1st Call Resolution	**88.0%**	88.3%	88.4%	88.0%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	**1.8**	1.9	1.2	2.7

The 2010 STI results for the calculation of controllable costs per customers, SAIDI and First Call Resolution were adjusted to remove the impact of the March sleet storm and Hurricane Igor.

The Company's STI program also includes an individual performance measure for Executives and Managers. 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	**75%**	**25%**
Other Executives	**60%**	**40%**
Managers	**50%**	**50%**

The individual measures of performance for Managers 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 2010 is established as a percentage of base pay for the three employee groups. For 2010, measures related to 'earnings', 'controllable operating costs/customers', 'SAIDI' and the two 'customer satisfaction' metrics were met, however, the 'safety' metric fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2008 to 2010:

STI Payout

	Target 2010	Actual 2010	Target 2009	Actual 2009	Target 2008	Actual 2008
President	**40%**	**54.1%**	**40%**	**52.7%**	40%	47.8%
Executive	**30%**	**40.3%**	**30%**	**40.3%**	30%	37.3%
Managers	**15%**	**18.1%**	**15%**	**19.2%**	15%	18.0%

STI actual payout rates for the President is higher than in the prior year, Executive category remained the same and Manager category decreased.

In dollar terms, the STI payouts for 2008 to 2010 are as follows:

	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
President	**$ 200,000**	**$ 195,000**	$ 160,000	$ 5,000
Executive	**280,000**	**292,000**	248,000	(12,000)
Managers	**226,800**	**239,500**	210,200	(12,700)
Total	**$ 706,800**	**$ 726,500**	$ 618,200	$ (19,700)
Year over year percentage change	**-2.71%**	17.52%	(2.89%)	

Note: The 2008-2009 results for STI paid to executives was adjusted to remove the impact of amounts paid to the Vice President, Customer and Corporate Services. This position was vacated effective January 12, 2010

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense.

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2008 to 2010.

	Base Salary	Short Term Incentive	Other	Total
2010				
Total executive group	$ 1,064,994	$ 480,000	$ 169,207	$ 1,714,201
Average per executive (4)	**$ 266,249**	**$ 120,000**	**$ 42,302**	**$ 428,550**
2009				
Total executive group	$ 1,102,106	$ 487,000	$ 114,258	$ 1,703,364
Average per executive (4)	**$ 275,527**	**$ 121,750**	**$ 28,565**	**$ 425,841**
2008				
Total executive group	$ 985,429	$ 408,000	$ 121,804	$ 1,515,233
Average per executive (4)	**$ 246,357**	**$ 102,000**	**$ 30,451**	**$ 378,808**
% Average increase 2010 vs 2009	**(3.37%)**	**(1.44%)**	**48.09%**	**0.64%**

Note: The 2008-2010 results for executive compensation were adjusted to remove the impact of amounts paid to Vice President, Customer and Corporate Services. This position was vacated effective January 12, 2010

Base salary for the executive group decreased from 2009 due to an extra pay period in fiscal 2009 compared to 2010. After normalizing for this the average base salary for 2010 is comparable to 2009. The increase in the total executive group relating to other compensation in 2010 versus 2009 was due to a $46,437 lump-sum vacation payment made to the President. Base salaries and STI payouts have been agreed to the 2010 Board of Directors' minutes.

Company Pension Plan

For 2010, we reviewed the accounts supporting the gross charge of $7,588,354 for the pension expense accounts of the Company. A detailed comparison of the components of pension expense for 2008 to 2010, including 2010 test year, is as follows:

	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual-Test	Variance 2010-2009
Pension expense per actuary	**6,173,359**	**$ 6,813,000**	$ 1,339,267	$ 1,883,316	$ (639,641)	$ 4,834,092
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**457,459**	**472,000**	452,802	413,650	(14,541)	4,657
Group RRSP @ 1.5%	**475,758**	**364,000**	486,002	498,497	111,758	(10,244)
Individual RRSP's	**533,262**	**587,000**	464,516	292,170	(53,738)	68,746
Less: Refunds (net of other expenses)	**(51,484)**	**(40,000)**	(69,360)	(48,000)	(11,484)	17,876
Total	**$ 7,588,354**	**$ 8,196,000**	$ 2,673,227	$ 3,039,633	$ (607,646)	4,915,127
Year over year percentage change	183.86%	-	(12.05%)	(45.39%)		

Overall, pension expense for 2010 is higher than 2009 primarily due to a decrease in the discount rate used to determine the Company's accrued defined benefit pension obligation, as well as the amortization of 2008 experience losses associated with pension plan assets. The discount used in 2009 was 7.5% compared to 6.5% in 2010.

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 P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expense is consistent with prior year and test year.

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. The increase of approximately $58,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2009 was primarily the result of wage increases.

Retirement Allowance

The retirement allowance costs incurred by the Company over the period from 2008 to 2010 are as follows:

(000's)	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual-Test	Variance 2010-2009
Early Retirement Program	$ -	$ -	$ -	$ -	$ -	$ -
Terminations and Severance	501	-	-	68	$ 501	501
Normal Retirements	240	325	117	236	$ (85)	123
Other Retiring Allowance Costs	(29)	-	3	4	$ (29)	(32)
Total	$ 712	$ 325	$ 120	$ 308	$ 387	$ 592
Year over year percentage change	493.33%	-	(61.04%)	(10.72%)		

The increase in 2010 as compared to 2009 is primarily due to the severance paid to a member of the executive. According to the Company, the actual normal retirements for 2010 were lower than anticipated when determining the test year.

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) and P.U. 43 (2009);
- compared intercompany charges for the years 2008 to 2010 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2010 and investigated any unusual items;
- vouched a sample of transactions for 2010 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.

As noted previously in the report, intercompany charges in 2010 were approximately $1 million higher than the test year. According to the Company, the test year does not include non-regulated expenses however the actual charges do include this activity.

The following table summarizes intercompany transactions from 2008 to 2010 for charges to and from Newfoundland Power Inc.:

	2010	2009	2008	2010-2009
Charges from related companies				
Regulated	$ 318,344	$ 148,141	$ 264,091	$ 170,203
Non-Regulated	1,404,293	1,083,521	918,057	320,772
Total	1,722,637	1,231,662	1,182,148	490,975
Charges to related companies	$ 956,364	$ 885,053	$ 1,513,023	$ 71,311

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 2010.

- Fortis Inc. estimated its net pool of operating expenses in Q4 2009 as part of its annual business planning process 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 evenly based upon 25% of the estimated annual amount.
- Similar to 2009, certain staffing and staffing related charges, as well as certain consulting and legal fees, were included in the pool of recoverable expenses. Of these expenses, Fortis deemed 50% of the CEO's and CFO's salary and related costs to be borne by Fortis Inc. for business development and consequently is excluded from the pool of recoverable expenses. Additionally, certain consulting and legal fees that are attributable to business acquisition activity are excluded. This is consistent with 2009.
- The model included a 'phase in' adjustment for allocating the recoverable expenses with 100% being recovered in 2010. The 'phase in' adjustment was meant to lessen the impact on the existing subsidiaries. For 2009, there was an 87.5% 'phase in' adjustment applied.
- Fortis Inc. used actual year-to-date expenditures up to October and estimated November and December's expenses for the determination of its actual 'true up' calculation. Fortis also used actual assets at September 30, 2010 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of November and December's expenditures had a minimal impact.

During the fourth quarter of 2010, a true-up calculation was completed to reflect actual recoverable expenses which was determined to be $1,043,000 and is summarized as follows:

2010 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$ 352,000	Non-regulated
Director Fees	211,000	Non-regulated
Consulting and Legal fees	108,000	Non-regulated
Trustee Agent Fees	45,000	Regulated
Audit and Other Fees	40,000	Non-regulated
Public Reporting Costs	49,000	Non-regulated
Annual Meeting Expenses	40,000	Non-regulated
Travel (Board and Other)	52,000	Non-regulated
Insurance (D&O)	50,000	Non-regulated
Other Costs	96,000	Non-regulated
	$ 1,043,000	
Less amounts previously billed:		
Q1 2010	$ 249,000	
Q2 2010	249,000	
Q3 2010	249,000	
Q4 2010 balance owing	$ 296,000	

For 2010, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 10.42%, fairly consistent from 10.89% in 2009.

As detailed above, trustee agent fees for $45,000 was the only expense 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, e.g. Non-Joint Use Poles charges and miscellaneous charges.

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 2008 to 2010 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Charges from Fortis Inc.				
Truseee fees and share plan costs	**$ 45,000**	$ 42,000	$ 34,000	$ 3,000
Miscellaneous	**12,493**	35,862	27,783	(23,369)
Non-Joint Use Poles	**13,512**	2,532	108,942	10,980
	$ 71,005	$ 80,394	$ 170,725	$ (9,389)
Year over year percentage change	**-11.68%**	-52.91%	-14.35%	
Charges to Fortis Inc.				
Postage and couriers	**$ 20,851**	$ 20,689	$ 19,907	$ 162
Printing, stationery and materials	**-**	129	135	(129)
IS charges	**-**	277	8,971	(277)
Staff charges	**500,948**	327,534	324,686	173,414
Staff charges - insurance	**213,164**	173,887	148,679	39,277
Pole removal and installation	**23,976**	23,599	19,295	377
Miscellaneous	**8,747**	11,969	6,056	(3,222)
	$ 767,686	$ 558,084	$ 527,729	$ 209,602
Year over year percentage change	**37.56%**	5.75%	(36.19%)	

The most significant fluctuation from our analysis of regulated intercompany charges for 2010 compared to 2009 related to staff charges. These charges to Fortis Inc. increased by $173,414 over 2009 primarily due to a Fortis Inc. potential acquisition project. Staff charges related to insurance increased $39,277 compared to 2009 primarily due to the timing effect of including both 2009 and 2010 payments for Fortis' Risk Manager in 2010. As well, there were increased labour and travel costs related to a trip to the United Kingdom for insurance marketing meetings. Miscellaneous charges have decreased $23,369 compared to 2009. The Company indicated that 2009 included a labour charge from Fortis Inc. for an employee who transferred from Newfoundland Power and it also included a pro-rata share of an invoice paid to their auditors.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2008 to 2010:

(Non-Regulated)	**Actual 2010**	**Actual 2009**	**Actual 2008**	**Variance 2010-2009**
Charges from Fortis Inc.				
Director's fees and travel	263,000	$ 226,000	$ 112,000	$ 37,000
Annual and quarterly reports	89,000	91,000	96,000	(2,000)
Staff charges	352,000	71,000	120,000	281,000
Miscellaneous	697,877	695,521	590,057	2,356
	$ 1,401,877	$ 1,083,521	$ 918,057	$ 318,356
Year over year percentage change	**29.38%**	18.02%	24.00%	

The most significant variances from our above analysis of non-regulated intercompany charges for 2010 compared to 2009 are as follows:

- Director's fees and travel expenses increased by $37,000 from 2009 due to the impact of Fortis' share price appreciation of 18.5% year over year as it impacts the accrual of costs associated with the Company's Directors' Deferred Share Unit Plan.

- Staff charges for 2010 have increased by $281,000. This increase was due to several factors: cost recovery for Newfoundland Power was at 100% for 2010 compared to 87.5% for 2009; 2010 ancillary income was allocated to all companies, 2009 excluded an allocation to Terasen Inc.; and the overall increase in recoverable salaries and benefits was mainly driven by an increases in stock option and performance share issuance costs.

The following table provides a summary and comparison of the other intercompany transactions for 2008 to 2010:

Intercompany Transactions (Other)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Charges to Fortis Properties				
Staff charges	**$ 1,247**	$ -	$ -	$ 1,247
Staff charges - insurance	**23,303**	13,517	26,905	9,786
IS charges	**-**	4,432	4,432	(4,432)
Stationary costs	**401**	714	1,081	(313)
Miscellaneous	**9,745**	4,691	6,301	5,054
	$ 34,696	$ 23,354	$ 38,719	$ 11,342
Charges from Fortis Properties				
Staff charges	**$ -**	$ 12,000	$ -	$ (12,000)
Hotel/Banquet facilities & meals	**69,612**	25,627	52,171	43,985
Miscellaneous	**11,814**	4,681	5,569	7,133
	$ 81,426	$ 42,308	$ 57,740	$ 39,118
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 4,417**	$ 17,688	$ 4,638	$ (13,271)
Staff charges	**-**	-	-	-
IS charges	**4,788**	2,424	2,424	2,364
Miscellaneous	**360**	273	850	87
	$ 9,565	$ 20,385	$ 7,912	$ (10,820)
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ -**	**$ -**	$ 9,172	$ -
Charges to Maritime Electric				
Staff charges	**$ 2,312**	$ 1,932	$ 6,036	$ 380
Staff charges - insurance	**1,346**	1,488	5,834	(142)
IS charges	**3,351**	2,424	2,424	927
Miscellaneous	**580**	701	1,081	(121)
	$ 7,589	$ 6,545	$ 15,375	$ 1,044

Intercompany Transactions (Other) Cont'd.	**Actual 2010**	**Actual 2009**	**Actual 2008**	**Variance 2010-2009**
Charges from Maritime Electric				
Staff charges	**$ 86,218**	$ -	$ -	$ 86,218
Miscellaneous	**7,338**	8,977	2,497	$ (1,639)
	$ 93,556	$ 8,977	$ 2,497	$ 84,579
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	**$ 1,134**	$ 8,743	$ 1,996	$ (7,609)
Staff charges	**37,456**	86,581	89,390	(49,125)
	$ 38,590	$ 95,324	$ 91,386	$ (56,734)
Charges to Belize Electricity				
Staff charges	**$ 3,739**	$ 11,424	$ 23,173	$ (7,685)
IS charges	**-**	4,155	4,240	(4,155)
Staff charges - insurance	**8,043**	8,436	661	(393)
Miscellaneous	**5,177**	4,863	19,564	314
	$ 16,959	$ 28,878	$ 47,638	$ (11,919)
Charges to Fortis US Energy Corporation				
Staff charges - insurance	**$ -**	$ -	$ 2,424	$ -
Charges to FortisAlberta Inc.				
Staff charges	**$ -**	$ -	$ 152,837	$ -
Staff charges - insurance	**540**	3,456	7,361	(2,916)
IS charges	**-**	-	391	-
Miscellaneous	**2,990**	3,441	18,180	(451)
	$ 3,530	$ 6,897	$ 178,769	$ (3,367)

Intercompany Transactions (Other) Cont'd.	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Charges from FortisAlberta Inc.				
Staff charges	**$ 64,914**	$ -	$ -	$ 64,914
Charges to FortisBC Inc.				
IS charges	**13,405**	8,310	8,310	5,095
Staff charges - insurance	**1,410**	1,620	9,344	(210)
Miscellaneous	**1,919**	2,203	3,362	(284)
	$ 16,734	$ 12,133	$ 21,016	$ 4,601
Charges from FortisBC Inc.				
Miscellaneous	**$ 9,859**	$ 16,462	$ 23,957	$ (6,603)
Charges to Terasen Gas Inc.				
Staff charges	**$ -**	$ -	$ 216	$ -
Staff charges - insurance	**540**	1,296	12,485	(756)
Miscellaneous	**6,212**	6,425	134	(213)
	$ 6,752	$ 7,721	$ 12,835	$ (969)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ -**	$ 888	$ -	$ (888)
Staff charges - insurance	**7,452**	6,837	1,167	615
Miscellaneous	**-**	101	81	(101)
	$ 7,452	$ 7,826	$ 1,248	$ (374)
Charges to Fortis Turks and Caicos				
Staff charges	**$ 37,679**	$ 103,091	$ 460,946	$ (65,412)
Staff charges - insurance	**8,255**	7,785	7,836	470
Miscellaneous	**877**	7,030	99,190	(6,153)
	$ 46,811	$ 117,906	$ 567,972	$ (71,095)

The most significant fluctuations from our analysis of other intercompany charges for 2010 compared to 2009 are as follows:

- Hotel/Banquet facilities & meals charges from Fortis Properties increased $43,985 over 2009 due to out-of-town crews staying at the Holiday Inn during Hurricane Igor.

- Staff charges from Fortis Alberta Inc. increased $64,194 compared to 2009. Increase is due to use of Fortis Alberta crews during Hurricane Igor.

- Staff charges from Maritime Electric increased over 2009 due to assistance provided during the ice storm and Hurricane Igor.

- Staff charges for insurance to Belize Electricity Company Ltd, decreased over the prior year. Labour and travel expenses were higher in 2009 due to greater participation of Newfoundland Power engineering staff in construction of a hydro generation project in Belize.

In Order 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 2010. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2010.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2010 General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2010 and noted no exceptions.

In P.U. 43 (2009), the Board ordered the Company, in consultation with the Consumer Advocate, to file no later than June 30, 2010 a report with alternatives and recommendations in relation to the policies for deployment of Newfoundland Power's staff to affiliated and other companies for emergency response. Confirmation was received from the Board that the report was filed on June 30, 2010.

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 2010 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Other company fees				
Other company fees	**$ 1,513**	$ 1,468	$ 1,429	$ 45
Regulatory hearing costs - other	**179**	482	39	(303)
Total other company fees	**$ 1,692**	$ 1,950	$ 1,468	$ (258)
Year over year percentage change	**-13.2%**	32.8%		
Deferred regulatory costs				
Total deferred regulatory costs	**$ 453**	$ 201	$ 200	$ 252
Year over year percentage change	**125.4%**	0.5%		

"Regulatory hearing costs – other" have decreased primarily due to consultant and legal fees incurred during 2009 that were associated with the 2010 General Rate Application. Other company fees in 2010 are lower than test year as the anticipated litigation costs associated with the Mobile Hydro Development were lower than forecast. 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 2008 to 2010 is as follows:

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Miscellaneous	**$ 1,046**	$ 777	$ 481	$ 269
Cafeteria and lunchroom supplies	**92**	79	72	13
Promotional items	**135**	197	97	(62)
Computer Software	**1**	4	1	(3)
Damage Claims	**143**	196	196	(53)
Community relations activities	**14**	12	15	2
Donations and charitable advertising	**194**	193	251	1
Books, magazines and subscriptions	**58**	53	50	5
Misc. lease payments	**20**	24	20	(4)
CDM rebates	**-**	-	154	-
HST clearing	**-**	-	-	-
Total miscellaneous expenses (Note 1)	**$ 1,703**	$ 1,535	$ 1,337	$ 168
Year over year percentage change	**10.94%**	14.81%	(14.40%)	

Note 1: $82,000 incorrectly coded to Miscellaneous in 2008 has been reclassified to Regular and Standby Labour. In addition, Conservation costs of $154,000 included in Miscellaneous in 2008 were segregated in the 2009 figures.

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2009 to 2010 these expenses have increased by 10.94% overall because of the write off of deferred costs relating to preliminary work done relating to the Company's Safety Management System, and work relating to a study of the Company's VHF radio system. The Company has confirmed that these deferred costs were not included in rate base during the deferral period.

Donations and charitable advertising included in miscellaneous expenses are non-regulated expenses.

Our procedures in this expense category for 2010 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 2010 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2010 Conservation and Demand Management Report with the Board. This report provided a summary of 2010 CDM activities and costs as well as the outlook for 2011. Costs have increased over the prior year mainly due to the fact that 2010 was the first full year of offering joint utility customer energy conservation programs under takeCHARGE. Costs in 2010 totaled $3,260,000 compared to $2,549,000 in 2009. Going forward, the Company will continue to promote and encourage participation in its takeCHARGE incentive programs. Newfoundland Power and Hydro also plan to introduce and enhance program offerings to include LED exit signs for commercial customers and high efficiency heat recovery ventilators for residential customers.

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 2010 and 2008, including 2010 test year, as follows:

(000's)	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual - Test	Variance 2010 - 2009
Vehicle expense	**1,504**	**1,492**	1,436	1,569	12	68
Operating materials	**1,271**	**1,082**	1,156	957	189	115
Plants, Subs, System Oper & Bldgs	**1,814**	**1,952**	1,907	1,782	(138)	(93)
Travel	**1,124**	**1,160**	1,016	1,290	(36)	108
Tools and clothing allowance	**1,139**	**1,108**	1,106	1,168	31	33
Taxes and assessments	**706**	**750**	765	(10)	(44)	(59)
Uncollectible bills	**801**	**963**	934	834	(162)	(133)
Insurances	**1,094**	**1,100**	1,043	1,344	(6)	51
Education, training, employee fees	**246**	**270**	215	265	(24)	31
Trustee and directors' fees	**387**	**394**	414	411	(7)	(27)
Stationary & copying	**299**	**337**	267	204	(38)	32
Equipment rental/maintenance	**773**	**721**	683	708	52	90
Communications (including postage and freight)	**3,009**	**2,918**	2,870	2,934	91	139
Advertising	**1,287**	**1,431**	1,079	553	(144)	208
Vegetation management	**1,672**	**1,550**	1,459	1,377	122	213
Computing equipment & software	**799**	**785**	801	475	14	(2)
Transfers (GEC)	**(2,429)**	**(1,900)**	(1,836)	(1,797)	(529)	(593)
Transfers (CDM)	**339**	**380**	(1,356)	-	(41)	1,695

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

- Operating materials increased by $115,000 in 2010 in comparison to 2009 and $189,000 in comparison to test year. Both variances are a result of Hurricane Igor. Additional materials were required for street light maintenance and trash rack cleaning at Hydro Plants.
- Systems operations decreased by $93,000 in 2010 in comparison to 2009 and $138,000 in comparison to test year. Both variances are as a result of deviation from the planned schedule of work in response to Hurricane Igor.
- Travel expenditures increased by $108,000 in 2010 resulting from Hurricane Igor and the need to move crews throughout the province based on the location of the needed work.
- Uncollected bills decreased in 2010 by $133,000. The Company's write offs net of collections decreased by $67,000 in comparison to 2009 and the Company's allowance for doubtful accounts decreased by $66,000. The Company indicated that the decrease in comparison to 2009 and test year is a result of general economic conditions. Equipment rental and maintenance increased by $90,000 in 2010 due to the costs associated with the response to Hurricane Igor.

- Communications increased by $139,000 in 2010 due to the expanded role of wireless communication devices field applications.
- Advertising increased by $208,000 in 2010 as compared to 2009 due to the continued promotion of new conservation initiatives. However, according to the Company, in 2010 the participation in some of the programs was higher than expected resulting in more funds being spent on rebates and less on advertising in comparison to what was forecast.
- Vegetation management increased by $213,000 in 2010 in comparison to 2009 and $122,000 in comparison to test year. Both variances are due to the impact of Hurricane Igor.
- Transfers (CDM) increased by $1,695,000 in 2010 due to a deferral expense of $337,000 relating to the amortization of deferred conservation costs approved in P.U. 43 (2009). In 2009 conservation costs of $1,356,000 were deferred resulting in a credit to this account and P.U. 43 (2009) approved the amortization of this amount over four years commencing in 2010.

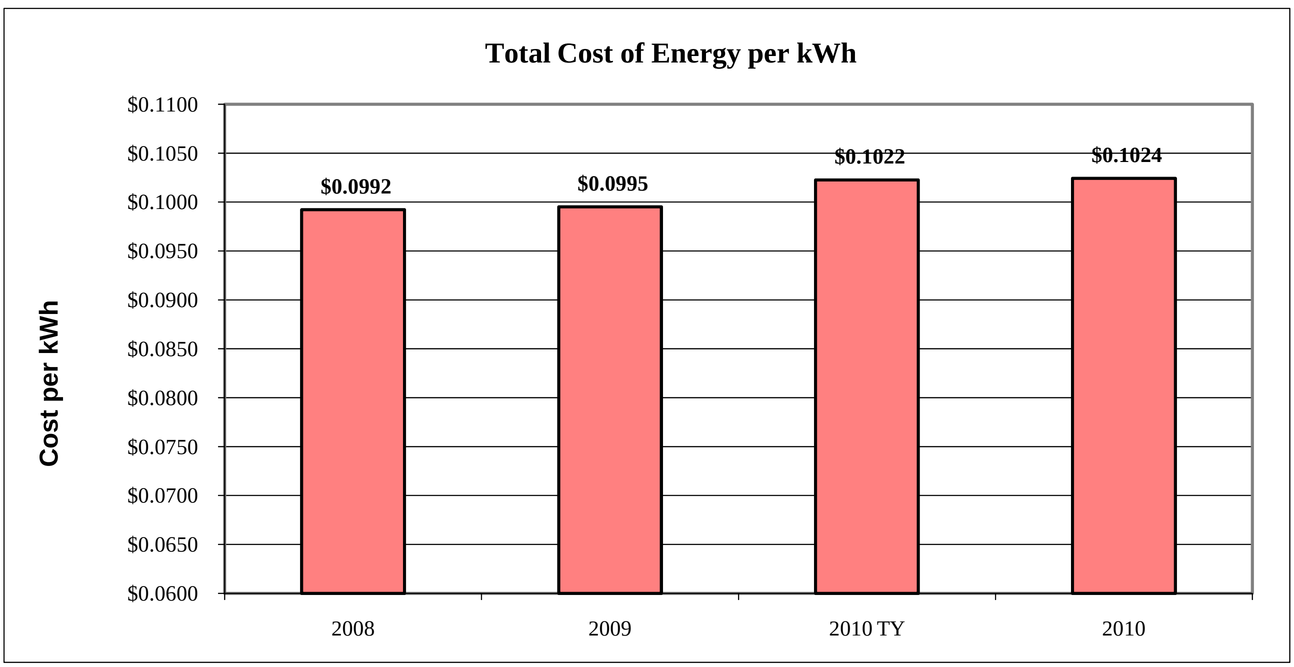
Other Costs

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 2008 to 2010, including 2010 test year:

		(000's)							
Year	**kWh sold**	**Operating Expenses**	**Purchased Power**	**Depreciation**	**Finance Charges***	**Income Taxes**	**Divdends and Return**	**Total Cost of Energy**	**Cost per kWh**
2008	5,208,200	$ 50,172	$ 336,658	$ 44,511	$ 33,507	$ 19,146	$ 32,895	$ 516,889	$ 0.0992
2009	5,299,000	$ 51,988	$ 345,656	$ 45,687	$ 34,555	$ 16,092	$ 33,201	$ 527,179	$ 0.0995
2010 TY	5,350,000	$ 59,885	$ 351,034	$ 47,239	$ 35,928	$ 17,098	$ 35,822	$ 547,006	$ 0.1022
2010	5,419,000	$ 62,211	$ 358,443	$ 47,220	$ 35,633	$ 15,870	$ 35,573	$ 554,950	$ 0.1024

* - Comparatives have been restated to reflect the reclassification of interest earned and interest on overdue accounts to 'other revenue'.



Purchased Power

We have reviewed the Company's purchased power expense for 2010 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.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the Gannett Fleming Depreciation Study, dated December 31, 2005 and assessed the reasonableness of depreciation expense.

The changes in depreciation rates and policies flowing from the Gannett Fleming Depreciation Study, dated December 31, 2005 were approved by the Board to be effective January 1, 2008 according to P.U. 32 (2007).

The objective of our procedures in this section was to ensure that the 2010 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the Depreciation Study undertaken by Gannett Fleming, Inc. dated December 31, 2005.

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 2010; and,
- assessed the overall reasonableness of the depreciation for 2010.

Amortization expense (excluding the Amortization True-Up Deferral) for 2010 is $43,358,000 as compared to $41,825,000 for 2009, representing a 3.5% increase. The change is attributable to an increase of depreciable assets (approximately $72,972,000), partly offset by an increase in the amortization of contributions from customers. The 2010 Amortization True-Up amount as approved under P.U. 32 (2007) was $3,862,000 which was the same amortization amount in 2009. Refer to the section of this report entitled "Regulatory Assets and Liabilities and Deferred Charges" for a discussion of the Amortization True-Up Deferral.

The Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005. As a result of this study a reserve variance or Amortization True-Up of $695,000 was identified. This amount represents the variances between the calculated accrued depreciation and the book accumulated depreciation which exceeds the 5% tolerance threshold. This balance was approved by the Board to be amortized over four years commencing in 2008.

Gannett Fleming has recommended that the Company continue to use the straight-line equal life group method that it has been using for a number of years for its plant assets with the exception of certain General and Communication accounts. Amortization accounting is considered appropriate for the General and Communication accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. However, the Board subsequently ordered, pursuant to P.U.43 (2009) that the Company file its next depreciation study relating to plant in service as of December 31, 2009. The purpose of this change was due to the requirement of the Company to file financial statements in 2011 that are in compliance with International Financial Reporting Standards and require comparative figures for 2010. The study for plant in service as of December 31, 2009 will provide more accurate and complete information for preparation of these comparative financial statements. According to the Company, this study is ongoing and is expected to be completed in the first half of 2011.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006) and P.U. 32 (2007), and the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005 have been incorporated into the Company's depreciation calculations for 2010.

Interest and 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:

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010 - 2009
Interest				
Long-term debt	$ 35,850	$ 34,547	$ 32,334	$ 1,303
Interest on related party loan	-	-	258	-
Other	334	411	1,236	(77)
Amortization				
Debt discount	232	235	235	(3)
Capital stock issue	37	37	62	-
Interest charged to construction	(820)	(675)	(618)	(145)
Total finance charges	$ 35,633	$ 34,555	$ 33,507	$ 1,078
Year over year percentage change	3.12%	3.13%	(4.10%)	

In the above table, the increase in interest on long term debt compared to 2009 is attributable to higher interest costs associated with the $65 million first mortgage bond that was issued in 2009. In 2009 this debt was only outstanding for eight months whereas in 2010 it was outstanding for the full twelve month period.

The interest on related party loan in 2008 relates to a short term loan with an interest rate of 3.15% provided to the Company in May 2008 by Fortis Inc. which was repaid in the third quarter of 2008. There have been no related party loans provided during 2010.

The decrease in other interest reflects changing interest rates on the Company's credit and demand facilities during 2010 compared to 2009.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2010 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2010 and have noted that the effective income tax rate decreased from 32.6% in 2009 to 30.9% in 2010. This decrease is primarily due to a decrease in the statutory tax rate of 1.0%, timing of pension funding and the allocation of the Part VI.1 tax liability and related Part 1 tax deduction from Fortis to the Company in 2010. This was offset by the tax treatment of regulatory amortizations and deferral accounts.

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 2010 is unreasonable.

Costs Associated with Curtailable Rates

In 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 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. The total of the curtailment credits for 2010 was $250,203 compared to the 2009 credits of $202,702. Total operating costs incurred by the Company in 2010 was $277,932 compared to $225,436. The increase in credits compared to the previous year is primarily a result of the number of successful customer curtailments.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and 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 2010 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2010 and investigated any unusual items;
* 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.

(000's)	2010	2009	2008	2010 - 2009
Charged from Fortis Companies:				
Annual report	$ 89,000	$ 91,000	$ 96,000	$ (2,000)
Directors' fees and travel	263,000	226,000	112,000	37,000
Staff charges	354,400	71,000	120,000	283,400
Miscellaneous	697,900	695,500	590,100	2,400
	1,404,300	1,083,500	918,100	320,800
Donations and charitable advertising	305,500	296,200	367,600	9,300
Executive short term incentive	104,500	113,700	191,500	(9,200)
Miscellaneous	109,400	93,700	106,800	15,700
	1,923,700	1,587,100	1,584,000	336,600
Less: Income taxes	615,500	523,700	530,600	91,800
Less: Part VI.1 tax adjustment	328,900	(139,200)	58,200	468,100
Total non-regulated (net of tax)	$ 979,300	$ 1,202,600	$ 995,200	$ (223,300)

In the table above the most significant fluctuation between 2010 and 2009 pertains to the Part VI.1 tax adjustment. This tax adjustment results from the payment by Fortis of dividends on its preferred shares. The Company has noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.'s corporate tax planning and preferred share dividend payment, and the Company's capacity to cover this tax.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2010 this represents an addition to non-regulated expenses (before tax adjustment) of $104,500 (2009 - $113,700). 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 32.0% which agrees with the Company's statutory rate as identified in the 2010 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 and Deferred Charges

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

Regulatory Assets and Liabilities

The following table summarizes Regulatory Assets and Regulatory Liabilities from 2008 to 2010:

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Regulatory Assets				
Rate stabilization account	**$ 3,723**	**$ 1,836**	**$ 2,490**	$ 1,887
OPEBs asset	**52,559**	**46,713**	**41,074**	$ 5,846
Weather normalization account	**4,204**	**6,031**	**5,910**	$ (1,827)
Amortization true-up deferral	**-**	**3,862**	**7,724**	$ (3,862)
Pension deferral	**4,793**	**5,921**	**7,048**	$ (1,128)
Replacement energy deferral	**-**	**600**	**766**	$ (600)
Deferred GRA costs	**506**	**951**	**402**	$ (445)
Conservation and demand management	**1,017**	**1,357**	**-**	$ (340)
Future income taxes	**120,327**	**118,701**	**-**	$ 1,626
	$ 187,129	**$ 185,972**	**$ 65,414**	$ 1,157
Regulatory Liabilities				
Rate stabilization account		**$ 418**		$ (418)
Municipal tax liability		**1,363**	**$ 2,727**	$ (1,363)
Unbilled revenue liability		**4,618**	**9,236**	$ (4,618)
Weather normalization account	**$ 6,892**	**-**	**-**	$ 6,892
Purchased power unit cost variance reserve	**-**	**688**	**895**	$ (688)
Future removal and site restoration provision	**49,485**	**48,660**	**47,961**	$ 825
Demand management incentive account	**994**	**-**	**426**	$ 994
	$ 57,371	**$ 55,747**	**$ 61,245**	$ 1,624

Note 1: The Weather Normalization Account , the Replacement Energy Deferral Account and the Purchased Power Unit Cost Variance Reserve balances in 2010 and 2009 included future income taxes however the 2008 balances were recorded net of future income taxes. This change is due to amendments to CICA Handbook Section 3465 effective for 2009.

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, 2010 were approved by the Board in P.U.19 (2010). The RSA regulatory asset of $3,723,000 represents a current portion of $1,847,000 and a non-current portion of $1,876,000. As of December 31, 2010, there was a charge to the RSA of $2,213,116 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007).

Pursuant to 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, 2010, the credit balance of $639,185 in the PEVDA account was credited to the RSA in accordance with P.U. 43 (2009).

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"). Total benefits paid in 2009 were $1,696,000 compared to a net benefits expense under accrual accounting of $7,542,000. In P.U. 43 (2009) the Board ordered the continuation of recording OPEBs on the cash basis and that the Company file with the Board 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 approximately $68.6 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 P.U. 31(2010). The OPEB Cost Variance Deferral Account will be treated similarly to the PEVDA, in that the balance in the account will be transferred to the RSA on March 31 in the year in which the difference arises.

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. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year. As at December 31, 2010, the non-reversing Degree Day component is a regulatory asset in the amount of $4,204,000 (2009 - $6,306,000) inclusive of future income tax. The balance in the Weather Normalization reserve represents the reversing component, which should tend to zero over time. As at December 31, 2010, the reversing component is a regulatory liability in the amount of $6,892,000 (2009 – $275,000 netted in regulatory asset). The net balance in the Weather Normalization reserve at December 31, 2010 is a regulatory liability of $2,688,000 (net of future income taxes the balance is $1,955,000).

The Amortization True-up Deferral (formerly known as the Depreciation True-up Deferral) was created to extend the impact of the Amortization True-up that arose from the Company's 2002 amortization study. In P.U. 32 (2007) the Board approved the Company's proposal to amortize the balance as at December 31, 2007 of $11,586,000 over a three year period commencing in 2008. The balance was fully amortized as at December 31, 2010.

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004).

The Replacement Energy Deferral account is related to the deferral of replacement energy costs associated with the Company's refurbishment of the Rattling Brook hydroelectric plant. P.U. 32 (2007) approved the amortization of $1,147,000 over a three year period which commenced in 2008. The balance was fully amortized as at December 31, 2010.

Deferred GRA costs relate to external costs incurred during the 2008 GRA and the costs related to the 2010 GRA. As at December 31, 2007 the Company estimated 2008 GRA costs to be $1,250,000. This balance was reduced by $647,000 to $603,000 in 2008 to reflect actual incurred costs. In P.U. 32 (2007) the Board ordered that 2008 GRA costs be amortized over a three year period beginning in 2008. In 2009, an amortization of $201,000 was recorded by the Company and the remaining $201,000 was amortized in 2010. As noted previously in the report, the Company deferred $760,000 of costs relating to the 2010 GRA. According to P.U. 43 (2009) the Board approved the amortization of a total amount of $750,000 over a three year period commencing January 1, 2010.

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 P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In 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 the amendment of CICA Handbook section 3465, commencing 2009 the Company is required to recognize future income tax assets and liabilities as well as offsetting regulatory assets and liabilities. This amendment does not affect the company's earnings or cash flows.

The Municipal Tax Liability account results from a timing difference related to the recovery and payment of municipal taxes. P.U. 32 (2007) approved the amortization of $4,087,000 over a three year period which commenced in 2008. The balance was fully amortized as at December 31, 2010.

The Unbilled Revenue Liability account arose due to the Company's transition from recognizing revenue on a billed basis to an accrual basis in 2006. The balance represents the unamortized balance of this account as of December 31, 2009. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of $13,854,000 over a three year period, which commenced in 2008. The remaining balance of $4,618,000 was fully amortized in 2010.

The Purchased Power Unit Cost Variance Reserve account was created to limit variations in the cost of purchased power associated with a demand and energy wholesale rate structure. This account was discontinued effective January 1, 2008 pursuant to P.U. 32 (2007) and replaced with the Demand Management Incentive Account. In P.U. 32 (2007), the Board approved the amortization of the 2006 balance of $1,342,000 in after tax costs over a three year period which commenced in 2008. This amount was fully amortized in 2010.

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchase power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2010, the variation in the account was $994,000. This balance was transferred as a credit to the RSA on March 31, 2011 pursuant to the Board's approval in P.U.7 (2011).

The Future Removal and Site Restoration Provision account represents estimated costs to be incurred in the future related to the removal of capital assets.

Expiration of Fixed Amortizations of Revenue and Cost Recovery Deferrals

As of December 31, 2010, six of the revenue and cost recovery deferrals noted above were fully amortized. The expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000, as outlined in the table below:

(000's)	2010 Test Year	
Revenue Deferrals		
2005 Unbilled Revenue	$ (6,791)	1
Municipal Tax Liability	(1,362)	
Cost Recovery Deferrals		
Depreciation	5,679	1
Replacement Energy	598	
Purchased Power Unit Cost Reserve	(688)	
2008 GRA Costs	201	
Revenue Requirement Impacts	$ (2,363)	

Note 1: Both of these deferrals are before the after tax impact.

On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of these deferrals, until a further Order from the Board. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 43(2009). In P.U. 30 (2010), the Board approved the deferred recovery of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations until a further Order of the Board. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which shall be charged the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differs that the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. The disposition of the balance in this account will be subject to a future Order of the Board.

This Cost Recovery Deferral Account will be reviewed as part of the Company's 2011 Annual Review.

Deferred Charges

The table below summarizes changes made to deferred charges during 2010 as summarized by the Company in Return 8 of its annual return.

(000's)	Balance December 31 2009	Additions During 2010	Reductions During 2010	Balance December 31 2010
Deferred pension costs	$ 103,723	$ 4,999	$ (6,173)	**$ 102,549**
Capital stock issue expense	38	-	(38)	**-**
Deferred credit facility issue costs		300	(42)	**258**
average rate base	$ 103,761	$ 5,299	$ (6,253)	**$ 102,807**

Note 1: Deferred Pension Cost December 31, 2010 balance includes $4.8 million in pension costs associated with the 2005 Early Retirement Program. Theses pension costs were originally $11.3 million and are being amortized over 10 years, beginning April 1, 2005.

Deferred pension costs include $4,793,000 related to a pension deferral which is included with Regulatory Assets in the Company's financial statements as discussed earlier in the report. The net change in this account represents the difference between employer contributions and pension expense during 2010.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges and regulatory deferrals for 2010 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account (PEVDA) and assess compliance with P.U. 43 (2009)***

In P.U. 43 (2009) the Board approved the creation of the Pension Expense Variance Deferral Account (PEVDA). 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 2010 PEVDA was calculated at $639,185. This balance was transferred to the rate stabilization account in March, 2010, however it was later determined that the amount calculated was overstated by $70,310. This error was due to the calculation of the variance being prepared using gross defined benefit pension expense instead of the defined benefit pension expense (net of GEC). This overstatement was a benefit to customers and Newfoundland Power has indicated to us that they will not be correcting this error.

We confirm that the 2010 PEVDA is calculated in accordance with P.U. 43 (2009) except relating to the overstatement of $70,310 as explained above.

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 2010 are as follows:

1. Introduced new safety initiatives as part of the Company's goal to improve contractor safety, including electrical safety training for pole and vegetation contractors.

2. The Company continued with mobile technologies projects, installing computers in additional trucks in the fleet.

3. The Company expanded the self serve option available on the corporate website. Customers can now make web and phone based payment arrangements and submit their own meter reading.

4. Completed several energy efficiency upgrades to the Company's electricity system, lighting upgrades in the offices and energy audits of the Company's facilities.

5. Maintained a Power Line Technician Apprentice Program to facilitate transfer of critical knowledge from senior employees.

6. Replaced over 500 hundred transformers with stainless steel units.

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 of the company:

Category	Measure	Actual 2008	Actual 2009	Actual 2010	Plan 2010	Measure Achieved
Reliability [3]	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	2.67	2.53	2.59	2.62	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	2.35	1.99	1.52	2.15	Yes
	Plant Availability (%)	95.2	96.9	96.8	96	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	89	90	89	89	Yes
	Call Centre Service Level (% per second)[2]	80/40	76/40	78/60	80/60	No
	Trouble Call Responded to Within 2 Hours (%)	91.3	90.8	83	85	No
Safety	All Injury/Illness Frequency Rate	2.7	1.2	1.9	1.8	No
Financial	Earnings (millions)	$32.3	$32.6	35.0	34.0	Yes
	Gross Operating Cost/Customer[1]	$208	$214	234	229	No

1. Excluding pension and early retirement costs.
2. Per cent of customer calls answered within 40 seconds. This was changed in 2010 to calls answered within 60 seconds
3. 2010 reliability statistics reported above exclude the impact of the March 2010 ice storm and Hurricane Igor

US GAAP Conversion Plan

Scope: ***Obtain an update of the Company's US GAAP conversion plan***

Newfoundland Power commenced its International Financial Reporting Standards ("IFRS') conversion project in 2007. At this time it was anticipated that the Company would convert to IFRS effective January 1, 2011. One of the biggest challenges identified by rate regulated entities, such as Newfoundland Power, in converting to IFRS was the lack of standards under IFRS dealing with regulatory assets and liabilities. The Company has reported that without specific guidance on accounting for rate-regulated activities a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Company's regulatory assets and liabilities.

The International Accounting Standards Board (the "IASB") had originally commenced a project on rate regulated activities, however, in 2010 the IASB deferred this project. As a result of this deferral the Canadian Accounting Standards Board (the "AcSB") allowed qualifying rate-regulated utilities to defer conversion to IFRS to January 1, 2012. Newfoundland Power met the definition of a qualifying utility and opted to avail of the one year deferral.

Due to the uncertainty of the future of rate-regulated accounting under IFRS many Canadian rate-regulated entities have opted to convert to US GAAP as opposed to IFRS. This option is available to Canadian companies that are registered with the US Securities and Exchange Commission (the "SEC"). Newfoundland Power has developed a conversion plan and a timeline for converting to US GAAP. The Company's conversion plan consists of the following phases:

Phase 1 – Scoping and Diagnostics: Consists of project initiation and awareness, identification of high-level differences between US GAAP and Canadian GAAP, and project planning and resourcing.

Phase 2 – Analysis and Development: Consists of detailed diagnostics and evaluation of the financial reporting impacts of adopting US GAAP, identification and design of operational and financial business processes, and development of required solutions to address identified issues.

Phase 3 – Implementation and Review: Involves implementation of the changes required by the Company to prepare and file its financial statements based on US GAAP beginning in 2012, and communications of the associated impacts.

The Company has engaged an external consultant to assist with a detailed assessment of US GAAP differences, US GAAP financial reporting, US governance rules and training requirements associated with the Company's evaluation.

The Company has provided the following comments regarding the benefits of adopting US GAAP versus IFRS:

- Broad consistency between accounting standards for financial reporting and regulatory purposes in considered desirable;
- The adoption of US GAAP in 2012 would result in fewer significant changes in the Company's current accounting policies as compared to those that may result with the adoption of IFRS; and
- US GAAP will allow the economic impact of rate-regulated activities to be recognized in financial statements in a manner consistent with the timing by which amounts are reflected in customer rates.

The Company expects to have completed an evaluation of regulatory implications associated with the potential adoption of US GAAP by the 3rd quarter 2011.

We agree with the Company's assessment that the adoption of US GAAP will likely result in fewer significant changes in the Company's current accounting policies as compared to IFRS. We recommend that the Board continue to follow up with the Company as its transition plan unfolds. In particular we recommend the Board request a presentation by the Company once it has completed its evaluation of the regulatory implications as noted above.

Grant Thornton
2011 Annual Financial Review of Newfoundland Power Inc.

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Board of Commissioners of Public Utilities
2011 Annual Financial Review of Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2011 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 2011 was $876,398,000 compared to average rate base for 2010 of $875,210,000. The increase of $1,188,000 over the prior year is primarily a result of an increase in net plant investment. The Company's calculation of the return on average rate base for 2011 was 8.14% (2010 - 8.24%) compared to an approved rate of return of 7.96%. The actual rate of return was at the upper end of the range approved by the Board (7.78% to 8.14%). 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 2011 was $392,266,000 (2010 - $390,844,000) and return on average common equity for the year ended December 31, 2011 was 9.00% (2010 – 9.21%). The cost of common equity per the Automatic Adjustment Formula was 8.38% (P.U. 32 (2010)). Since the Company's return on average common equity exceeded the amount as determined by the formula by greater than 50 bps, a report was required to be filed as per P.U. 32 (2007). A report was filed by the Company on March 30, 2012, noting "the principal contributor to the higher rate of ROE was the revision to the terms for the shared use of utility poles and related infrastructure between Newfoundland Power and Bell Aliant ("Joint Use"). The revision of these terms was an extraordinary event." The Company's common equity was calculated at 44.74% of total capital. As a result, the Company's capital structure for 2011 did not exceed the proportion of common equity deemed for ratemaking purposes in Order No. P.U. 43 (2009) to be 45%.

The actual capital expenditures (excluding capital projects carried forward from prior years) was 2.73% under budget in 2011. The capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $2,341,000 (2.76%). However, for each category of expenditure, the variances ranged from an over-budget of 33.93% to an under-budget of 80.94%. Significant variances are explained in our report.

The Company experienced a 3.22% increase in revenue from rates in 2011 as compared to 2010. The increase can be explained by an increase in customer rates and demand in Gigawatt hours sold.

Net operating expenses in 2011 increased by $14,673,000 from 2010. The increase is primarily due to an increase in labour, intercompany charges, conservation, retirement allowances, pension and early retirement program costs, the accrual of other post-employment benefits ("OPEBs") and conservation demand management transfers. These and other 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 2011 are unreasonable.

Non-regulated expenses, net of tax, increased in 2011 by $624,400. This variance was largely explained by a decrease of $550,200 related to the Part VI.1 tax adjustment as allocated by Fortis Inc. among its subsidiaries.

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

Based on our review, the 2011 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

Based on our review, the 2011 Other Post Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with P.U. 31 (2010).

Based on our review, the 2011 Optional Seasonal Rate Revenue and Cost Recovery Account operated in accordance with P.U. 8 (2011). We did note that due to an administrative error, the application for the disposition of the balance in this account was filed on March 30, 2012, rather than on or before March 1, 2012, as required in the Board Order.

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 2011 the Company met four out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey", "Trouble Call Responded to Within 2 Hours" 'All Injury/Illness Frequency Rate" and "Gross Operating Cost/Customer". The Company excluded the impact of a December storm from its reliability statistics.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2011 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 assess reasonableness and prudence in relation to sales of power and energy and 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 costs,
   - 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 as per P.U. 32 (2007) and P.U. 43(2009).

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to P.U. 19 (2003), P.U. 32 (2007) and P.U 43 (2009).

5. Examine the Company's 2011 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 dated December 31, 2005. Assess reasonableness of depreciation expense. Review with Company officials the status of its depreciation study relating to plant in service as of December 31, 2009.

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 P.U. 43 (2009).

11. Conduct an examination of the Other Post-Employment Benefits Expense Variance Deferral Account to assess compliance with P.U. 31 (2010).

12. Conduct an examination of the Optional Seasonal Rate Revenue and Cost Recovery Account to assess compliance with P.U. 8 (2011).

13. Complete a review of the 2011 Board Orders to assess compliance with Board directives.

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

- inquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

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.

The financial statements of the Company for the year ended December 31, 2011 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 7, 2012. 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 April 9, 2012, the Company filed a summary of revisions to its system of accounts with the Board, along with a copy of the revised System of Accounts. In submitting these changes the Company noted that the revisions were mainly due to changes arising from specific Board Orders, as well as adoption of United States Generally Accepted Accounting Principles ("US GAAP"). The revisions consisted of the addition of new accounts, the deletion of older accounts, as well as account description changes.

A summary of the changes to accounts and returns are listed below:

Accounts that have been added:

Account Number	Description	Category
92xxx	Customer Jobbing	Assets
18649/18650	Optional Seasonal Rate Revenue and Cost Recovery Account	Assets
1866x/1451x	Employee Future Benefits Regulatory Assets and Liabilities Account	Assets
23502	Other Post Employee Benefits	Liabilities
24222	Other Post Employment Benefits Cost Variance Deferral Account	Liabilities
24228	Pension Expense Variance Deferral Account	Liabilities
2350x	Defined Benefit Pension Plans and Other Liabilities	Liabilities
22409	Cost Recovery Deferral 2010 Regulatory Amortizations	Liabilities
272xx	Provision for Income Taxes Long Term	Liabilities
4x15x	Domestic Seasonal Optional Rate	Operating Revenues
41114	Deferred Revenues – PEVDA	Operating Revenues
41115	Deferred Revenues – OPEBs Variance Deferral Account	Operating Revenues
41116	Deferred Revenues, Domestic Seasonal Optional Rates	Operating Revenues
643xx	Other Post Employment Benefits Costs	Operating Expenses

Accounts that have been deleted:

Account Number	Description	Category
147xx	Unbilled Revenue Increase Reserve	Assets
20407	Purchased Power Unit Cost Variance Reserve	Liabilities
22402	Unrecognized 2005 Unbilled Revenue	Liabilities

Accounts that have names and/or definitions changed:

Account Number	Description	Category
186xx	Miscellaneous Deferred Charges	Assets
4x5xx/40700	Miscellaneous Non-Consumer Revenue	Operating Revenues
416xx/5x590	Pole Related Revenues and Joint Use Revenues	Operating Revenues

Annual Returns that have been revised:

Return Number	Description
19	Current definition: Pension Expense Variance Deferral Account and the Other Post Employment Benefits Variance Deferral Account
19	Prior definition: Purchased Power Unit Cost Variance Reserve

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, 2011 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 2011 was $876,398,000 which is an increase of $1,188,000 (0.14%) over the average rate base for 2010 of $875,210,000.

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 2011; 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 2011, 2010 and 2009 (all figures shown are averages):

(000)'s	2011	2010	2009
Net Plant Investment			
Plant Investment	$ 1,382,782	$ 1,366,106	$ 1,312,224
Accumulated Depreciation	(580,586)	(573,627)	(550,832)
CIAC's	(29,640)	(29,642)	(27,450)
	772,556	762,837	733,942
Additions to Rate Base			
Deferred Charges (a)	100,354	103,284	102,041
Deferred Energy Replacement Costs (b)	-	192	575
Cost Recovery Deferral for Seasonal/TOD Rates (c)	114	-	-
Cost Recovery Deferral for Hearing Costs (d)	380	354	301
Cost Recovery Deferral for Regulatory Amortizations (e)	821	-	-
Cost Recovery Deferral – Conservation (f)	568	815	474
Amortization True-up Deferral (g)	-	1,931	5,793
Customer Finance Programs (h)	1,587	1,663	1,728
Weather Normalization Reserve (i)	-	983	4,914
	103,824	109,222	115,826
Deductions from Rate Base			
Weather Normalization Reserve (i)	3,487	-	-
Municipal Tax Liability (j)	-	682	2,045
Unrecognized 2005 Unbilled Revenue (k)	-	2,309	6,927
2010 Hearing Costs Adjustment (d)	3	-	-
Other Post Employment Benefits (l)	3,600	-	-
Customer Security Deposits (m)	700	643	683
Accrued Pension Obligation (n)	3,663	3,464	3,261
Future Income Taxes (o)	2,240	2,957	1,741
Demand Management Incentive Account (p)	964	338	213
Purchased Power Unit Cost Variance Reserve (p)	-	224	670
	14,657	10,617	15,540
Average Rate Base before Allowances	861,723	861,442	834,228
Rate Base Allowances			
Materials and Supplies	5,012	4,476	4,366
Cash Working Capital	9,663	9,292	9,899
	14,675	13,768	14,265
Average Rate Base	$ 876,398	$ 875,210	$ 848,493

(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 $100,354,000 (2010 - $103,284,000) included in the 2011 rate base consists of average deferred pension costs of $100,089,000 (2010 - $103,284,000) and credit facility costs of $265,000.

(b) In P.U. 32 (2007) the Board approved the deferral of 2007 replacement energy costs associated with the Rattling Brook Hydro Generating plant refurbishment in the amount of $1,147,000 over a three-year amortization period. These costs were fully amortized at the end of 2010.

(c) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to 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". The calculation of the 2011 average rate base incorporates $114,000 related to this deferral account.

(d) In P.U. 43 (2009) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2010, hearing costs related to the 2010 GRA in the amount of $750,000. During 2010, the Company deferred $760,000, $10,000 higher than the approved amount, of 2010 GRA hearing costs. In P.U. 26(2011), the Board ordered Newfoundland Power to adjust the recovery of its 2010 hearing costs to reflect total costs of $750,000, as originally approved in the Board Order. Average rate base includes an addition of $380,000 which represents the unamortized average balance of the original $760,000 offset by a deduction of $3,000.

(e) On August 31, 2010 Newfoundland Power submitted an application proposing to defer recovery, until a further Order of the Board, of the amount of $2,363,000 ($1,642,000 after tax) in 2011 to offset the net impact of the expiring amortizations relating to the Municipal Tax Liability, Unrecognized 2005 Unbilled Revenue, Deferred Energy Replacement Costs and the Purchased Power Unit Cost Variance Reserve. This application was approved by the Board in P.U. 30 (2010). Included in the calculation of the average rate base for 2011 is $821,000 related to this deferral.

(f) In P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,0000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan.

(g) The Amortization True-up Deferral was created to extend the impact of the Amortization True-up that arose from the Company's 2002 amortization study filed in the 2003 GRA. In P.U. 32 (2007) the Board approved the Company's proposal to amortize the balance at December 31, 2007 of $11,586,000 over a three year period commencing in 2008. The balance was fully amortized as at December 31, 2010.

(h) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2011 average rate base incorporates $1,587,000 (2010 - $1,663,000) related to these programs.

(i) In P.U. 32 (2007) the Board approved the amortization of the 2006 balance in the Degree Day Component of the Weather Normalization Reserve. Since it was determined that the balance of $6,800,000 was unlikely to reverse, the amount was to be amortized over five years. The calculation of the 2011 average rate base incorporates amortization of $1,366,000 for the non-reversing portion of the reserve.

The Weather Normalization reserve was also impacted during 2011 by the following:

i. $532,000 transfer to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer
ii. $1,167,000 transfer to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer

The impact of these transfers plus the amortization of $1,366,000 resulted in a total transfer to the reserve of $3,065,000. The ending balance in this reserve account totaled $5,020,000 (i.e. amount owed to customers).

(j) The Municipal Tax Liability arose due to a timing difference between the recovery and payment of municipal taxes. This account was being amortized over a three year period commencing in 2008 pursuant to P.U. 32 (2007) and was fully amortized at the end of 2010.

(k) In P.U. 40 (2005) the Board ordered Newfoundland Power to deduct from rate base the average balance in the Unrecognized 2005 Unbilled Revenue Account which was $2,309,000 in 2010 (2009 - $6,927,000). This unbilled revenue balance arose as a result of the approval to adopt the accrual method of revenue recognition in 2006. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of $13,854,000 over a three year period, which commenced in 2008. The balance of the Unrecognized 2005 Unbilled Revenue was fully amortized at the end of 2010.

(l) Other Post Employment Benefits is equal to the difference, at December 31, 2011, between the OPEBs liability of $56,255,000 and the OPEBs asset of $49,056,000. The calculation of the 2011 average rate base incorporates $3,600,000 relating to this difference.

(m) 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 2011 average rate base incorporates $700,000 (2010 - $643,000) related to customer security deposits.

(n) The 2011 average rate base calculation incorporates $3,663,000 (2010 - $3,464,000) 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.

(o) In 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 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 the future income taxes liability related to pension costs and OPEBs included in the 2011 average rate base is $402,000 and ($987,000) respectively. The remaining balance of the future income tax liability in the amount of $2,825,000 relates to capital assets.

(p) In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland Hydro's proposed demand and energy rate structure. This reserve mechanism is the Purchased Power Unit Cost Variance Reserve used to limit variations in the cost of purchased power associated with the demand and energy structure implemented as of January 1, 2005. In P.U. 32 (2007) the Board approved the amortization of the 2006 balance of $1,342,000 over a three year period beginning in 2008. The balance was fully amortized at the end of 2010. In addition, P.U. 32 (2007) also approved the Company's proposal to discontinue the Purchased Power Unit Cost Variance Reserve Account and establish the Demand

Management Incentive Account. In P.U. 9 (2012) the Board approved the disposition of the 2011 balance of the Demand Management Incentive Account of $1,800,628 (less the related income tax effect of $549,192) by means of a credit to the Rate Stabilization Account as of March 31, 2012.

The net change in the Company's average rate base from 2010 to 2011 can be summarized as follows:

(000's)	2011	2010
Average rate base - opening balance	$ 875,210	$ 848,493
Change in average deferred charges and deferred regulatory costs	(4,340)	(2,608)
Average change in:		
Plant in service	16,677	53,881
Accumulated depreciation	(6,959)	(22,795)
Contributions in aid of construction	2	(2,191)
Weather normalization reserve	(4,470)	(3,931)
Unrecognized 2005 unbilled revenue	2,309	4,618
Other post employment benefits	(3,600)	-
Future income taxes	717	(1,216)
Other rate base components (net)	852	959
Average rate base - ending balance	$ 876,398	$ 875,210

In accordance with the new CICA Handbook *Section 3031 – Inventory*, the Company reclassified inventories of $4.3 million to the account *capital assets - construction materials* on the balance sheet as they are held for the development, construction, maintenance and repair of other capital assets. As at December 31, 2011, $5.4 million (2010 - $4.8 million) in construction materials were included in Plant Investment for financial reporting purposes but have been excluded from the Plant Investment component of the average rate base. Consistent with prior year's calculation, these inventories are included in the materials and supplies component of the average rate base.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2011 average rate base and conclude that the 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 2011 was 8.14% (2010 - 8.24%). 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 2011, the return on average rate base is calculated in accordance with the methodology approved in P.U. 43 (2009).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2009 to 2011 is set out in the table below.

	2011	2010	2009
Actual Return on Average Rate Base	8.14%	8.24%	8.12%
Upper End of Range set by the Board	8.14%	8.41%	8.55%
Lower End of Range set by the Board	7.78%	8.05%	8.19%

In P.U. 32 (2010) the Board approved the Company's rate of return on average rate base for 2011 of 7.96%, within a range of 7.78% to 8.14%. As noted above, the Company's actual return on average rate base for 2011 was 8.14% which was at the upper end of the range set by the Board. The rate of return for 2010 was within the range set by the Board, while the 2009 rate fell short by 7 basis points below the lower range.

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 P.U. 43 (2009) the Board reconfirmed its previous position as per P.U. 32 (2007) 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 2011 as reported in Return 24 is as follows:

	2011 Average			2010	2009
		(000's)	Percent	Percent	Percent
Debt	$	475,471	54.22%	54.41%	54.26%
Preferred equity		9,096	1.04%	1.04%	1.09%
Common equity		392,266	44.74%	44.55%	44.65%
	$	876,833	100.00%	100.00%	100.00%

Pursuant to 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 2010 year in Return 26 as well as an explanation of the variance in the actual embedded cost of debt from the cost forecast for the 2010 test year. The embedded cost of debt for 2011 was 7.66% which represents a 3 bp (0.03%) increase from 2010 embedded cost of debt of 7.63%.

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 Board Order P.U. 43 (2009).

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, 2011 is included on Return 27 of the annual report to the Board. The average common equity for 2011 was $392,266,000 (2010 - $390,844,000). The Company's actual return on average common equity for 2011 was 9.00% (2010 – 9.21%).

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 P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007) and P.U. 43(2009).
- recalculated the rate of return on common equity for 2011 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 43(2009).

In 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 2011 the cost of common equity per the Formula was 8.38% (P.U. 32 (2010)). The actual return on average common equity for 2011 was 9.00% as noted above. This return was above the 50 basis point trigger and as such a report was filed by the Company on March 30, 2012. In this report the Company noted that "the principal contributor to the higher rate of ROE was the revision of the terms for the shared use of utility poles and related infrastructure between Newfoundland Power and Bell Aliant ("Joint Use"). The revision of these terms was an "extraordinary event". In P.U. 25 (2011) the Board ordered that the operation of the Formula to establish a rate of return on rate base for Newfoundland Power for 2012 be suspended. The rate of return on rate base of 7.96% was approved for 2012 on an interim basis.

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)	2011	2010	2009
Net income	$ 34,252	$ 35,573	$ 33,201
Income taxes	15,876	15,870	16,092
Interest on long term debt	35,444	35,850	34,547
Interest during construction	(970)	(820)	(675)
Other interest and amortization of debt discount costs	1,010	566	646
Total	$ 85,612	$ 87,039	$ 83,811
Interest on long term debt	$ 35,444	$ 35,850	$ 34,547
Other interest and amortization of debt discount costs	1,010	566	646
Total	$ 36,454	$ 36,416	$ 35,193
Interest coverage (times)	2.35	2.39	2.38

The above table shows that the interest coverage decreased in 2011 over 2010 by 0.04 times. The decrease over prior year is primarily due to the Company's lower pre-tax earnings.

In 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 2011 is 2.35 times.

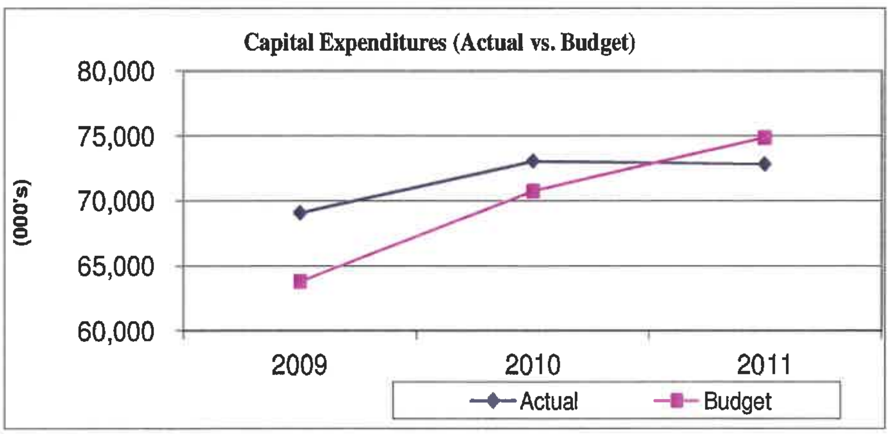
Capital Expenditures

Scope: ***Review the Company's 2011 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 2009 to 2011.

(000's)	2009	2010	2011	
Actual	69,103	73,082	**72,846**	(1)
Budget	63,821	70,779	**74,894**	
Over (under) budget	8.28%	3.25%	**(2.73%)**	

(1) Total expenditures per the 2011 Capital Budget report include the carryover amount of $1,032,000 for a total of $73,878,000. The carryover amount is made up of four projects - $350,000 relating to facilities rehabilitation, $300,000 relating to rebulding transmission lines, $300,000 relating to feeder additions and $82,000 relating to renovation work. According to the Company, these expenditures will occur in 2012.



The following table provides a summary of the capital expenditure activity in 2011 as reported in the Company's *"2011 Capital Expenditure Report"*.

	Capital Budget			Actual Expenditures		
(000's)	**2010**	**2011**	**Total**	**2010**	**2011**	**Total**
2011 Capital Projects and GEC	$ -	$ 74,894	**$ 74,894** [1]	$ -	$ 72,846	**$ 72,846**
2010 Projects carried to 2011						
Substation Refurbishment and Modernization (2)	4,043	-	**4,043**	3,201	1,453	**4,654**
Rebuild Transmission Lines (3)	5,915	-	**5,915**	3,139	1,872	**5,011**
	9,958	-	**9,958**	6,340	3,325	**9,665**
	$ 9,958	$ 74,894	**$ 84,852**	$ 6,340	$ 76,171	**$ 82,511**

(1) Approved by Orders P.U. 28 (2010), P.U. 8 (2011) and P.U. 11 (2011)
(2) The total original budget for the Substation Refurbishment and Modernization project as noted above was $4,043,000. Total expenditures to December 31, 2011 were $4,654,000 which is $611,000 above the original budget. The company noted that the unfavourable variance was the caused by higher contract prices than were anticipated in 2009
(3) The total original budget for the Rebuild Transmission Lines project as noted above was $5,915,000. Total expenditures to December 31, 2011 were $5,011,000 which is $904,000 below the original budget. Most of the variance is due to the fact that approximately $600,000 is now included in the 2012 capital budget

The largest variances by dollar amount relate to the following asset classes: transmission, distribution, general expenses capital and generation – hydro. Each of these categories is reviewed in greater detail below.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows (note: variances with an actual less than budget have been described as 'favourable' and variances with an actual in excess of budget have been described as 'unfavourable'):

(000's)	2011 Budget [1]	2011 Actuals	Variance	%
Generation - Hydro	$ 9,496	$ 8,576	$ (920)	(9.69%)
Generation - Thermal	268	252	(16)	(5.97%)
Substations	15,690	15,181 [2]	(509)	(3.24%)
Transmission	10,660	8,400 [2]	(2,260)	(21.20%)
Distribution	36,842	38,210	1,368	3.71%
General property	1,792	1,757	(35)	(1.95%)
Transportation	2,254	2,272	18	0.80%
Telecommunications	572	109	(463)	(80.94%)
Information systems	3,728	3,699	(29)	(0.78%)
Unforeseen	750	305	(445)	(59.33%)
General expenses capital	2,800	3,750	950	33.93%
Total	$ 84,852	$ 82,511	$ (2,341)	(2.76%)

1 -Includes prior year and current year budgeted amounts as there were projects incomplete at the previous year end. The 2011 budget for Substations includes $4,043,000 carried forward from the 2010 budget relating to Substation Refurbishment and Modernization. The 2011 budget for Transmission includes $5,915,000 carried forward from the 2010 budget relating to Rebuilding Transmission Lines

2 - 2011 actuals include the total expense for projects carried forward from 2010. Total costs for the Substation category relate to the carry forward of Substation Refurbishment and Modernization of which $3,201,000 was spent in 2010 with a further $1,453,000 spent in 2011. Total costs for the Transmission category relate to the carry forward of Rebuild of Transmission Lines of which $3,139,000 was spent in 2010 with a further $1,872,000 spent in 2011

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 $2,341,000 (2.76%). However, for each category of expenditure, the variances ranged from an over-budget of 33.93% to an under-budget of 80.94%. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. In addition, the Company has noted that there is $1,032,000 related to projects that will be carried forward to 2012 which include: Facility Rehabilitation ($165,000), Horse Chops Rewind and Rotor Re-insulation ($185,000), Rebuild Transmission Lines ($300,000), Feeder Additions for Growth ($300,000), and Kenmount Road Building Entrance Renovation ($82,000) The explanations provided by the Company indicate that the capital expenditure variances for 2011 were caused by a number of factors. The more significant variances noted above were as a result of the following:

Generation - Hydro

- The favourable variance of $920,000 is primarily due to a carryover of the following projects: Facility Rehabilitation ($165,000) and Horse Chops Rewind and Rotor Re-insulation ($185,000). Also contributing to the variance is a $296,000 favourable variance on the Horse Chops Rewind and

Rotor Re-Insulation project. This variance was a result of competitive bids from suppliers which led to a lower contract price than was anticipated in the original project estimate. The Facility Rehabilitation and Port Union and Lawn Rehabilitation projects also had favourable variances of $160,000 and $168,000 respectively. The favourable variance was partially offset by a $196,000 unfavourable variance on the Hydro Plan Production Increase. Delays in the environmental approval process resulted in the work at Sandy Lake being tendered later in the construction season. As a result, the work was completed when weather conditions were less than favourable which led to an increase in contract pricing. Also, during the detailed engineering phase it was determined that raising the level of the reservoir would flood an adjacent cottage property thus additional monies were required to raise the level of the cottage property.

Substations

- Substations had a favourable variance of $509,000. However, included in the budget is $866,000 related to Substation Refurbishment & Modernization project initially approved for 2011 that was deferred and resubmitted for approval in the 2012 Capital Budget Application. The PCB Bushing Phaseout project contributed $562,000 to the favourable variance. The scope of the 2011 PCB project was completed as planned but less time was required to complete the identified work than anticipated during the budgeting process. The favourable variances were partially offset by an unfavourable variance of $468,000 in the Replacements Due to In-Service Failures project. Three extraordinary items were addressed in 2011 at a total cost of $467,000: St. John's Main transformer failure, St. John's Main station service replacement, and Clarenville transformer radiator replacement. The favourable variances were further offset by increased costs of $611,000 relating to work completed on the Grand Falls substation due to increased contract prices. The increased prices were a result of the estimate being prepared in 2009 for the 2010 budget.

Transmission

- The favourable variance of $2,260,000 is partially due to the reduction of expenditures by approximately $822,000 related to the rebuild of transmission line 21L. The project was deferred to 2012 and has been approved as part of the 2012 Capital Budget. The rebuild of transmission line 21L was deferred to accommodate the 2010 work which was carried into 2011. In addition, competitive bidding resulted in a contract price for work on 25L that was $250,000 below the budget estimate. Also contributing to the variance is the 2010 Rebuild Transmission Lines project. Work on 110L scheduled for 2010 at a cost of approximately $600,000 was deferred and is now included in the 2012 Capital Budget.

Telecommunications

- The favourable variance of $463,000 is primarily due to the fact that no construction work was performed in relation to the Fibre Optic Circuit Replacement project. Newfoundland Power believes that recent increased competition and capacity in the local telecommunications market may affect the pricing of fibre capacity. As a result, Newfoundland Power is currently re-evaluating its Fibre Optic Replacement requirements.

General expenses capital

- The unfavourable variance of $950,000 is related to an increase in the allocated portion of pension expense. Pension expenses increased from $2,623,000 in 2009 to $7,588,000 in 2010 and to $11,566,000 in 2011 as a result of the amortization of 2008 losses associated with the pension plan assets along with a lower discount rate being used to determine the Company's accrued obligation under its defined benefit pension plan.

Distribution

The unfavourable variance in Distribution of $1,368,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 11,568	$ 11,420	$ (148)	(1.28%)
Meters	1,810	1,763	(47)	(2.60%)
Services	3,073	4,682	1,609	52.36%
Street Lighting	2,195	2,211	16	0.73%
Transformers	7,999	7,196	(803)	(10.04%)
Reconstruction	3,609	3,967	358	9.92%
Rebuild distribution lines	3,088	2,413	(675)	(21.86%)
Relocate/Place Distribution Lines for Third Parties	782	2,863	2,081	266.11%
Distibution Reliability Initiative	521	380	(141)	(27.06%)
St. John's Trunk Feeders	160	124	(36)	(22.50%)
Feeder Additions for Growth	1,281	470	(811)	(63.31%)
Replace Mercury Vapour Street Lights	581	540	(41)	(7.06%)
AFUDC	175	181	6	3.43%
Total	$ 36,842	$ 38,210	$ 1,368	3.71%

- The budget for "Services" consists of expenditures required to connect new services and replace existing services. The unfavourable variance of $1,609,000 is primarily due to an extraordinary number of service replacements in early 2011 that are attributed to the effects of storm damage incurred during Hurricane Igor in September 2010.

- The favourable variance in "Transformers" of $803,000 is a result of lower than anticipated contract prices obtained through competitive tendering. In addition, there was a reduction in the requirement for transformer replacements, offset somewhat by higher than anticipated growth.

- The favourable variance of $675,000 in "Rebuild Distribution Lines" is a result of less rebuild work being performed during the year. The amount of customer-driven work, third party and storm related work completed in 2011 was significantly higher than anticipated, resulting in less rebuilds. All high priority work identified in inspections of the 43 distribution lines was completed while a portion of the lower priority work, approximately $300,000, identified in those inspections was deferred.

- The unfavourable variance of $2,081,000 in "Relocate/Place Distribution lines for Third Parties" was driven by higher than normal system upgrade activity by telecommunications service providers. Approximately $1.65 million was spent upgrading distribution lines to accommodate third party attachments. An additional $546,000 was spent to accommodate highway construction. A portion of these costs amounting to $641,000 was recovered through Contributions in Aid of Construction.

- The favourable variance of $141,000 in "Distribution Reliability Initiative" is attributed to a reassessment of the remaining requirements resulting in less work being required for 2011. This was the final year of a three year upgrade. In 2010, work required on the feeder as a result of the damage caused by Hurricane Igor duplicated some of the work scheduled to be done under the Distribution Reliability Initiative which resulted in the reassessment.

- The favourable variance of $811,000 in "Feeder Additions for Growth" was a result of two projects not being completed. The start of the work on the new Pulpit Rock feeder was delayed due to difficulties in getting government permits. The work is ongoing, with the expenditures estimated at $300,000 being carried forward to 2012. The overall project is expected to be approximately $140,000 under budget. The planned work on the aerial feeders out of St. John's Main substation, estimated at $450,000 was not completed in 2011 due to a failure to obtain the agreement of affected landowners. This work will now be reviewed as part of an overall review of the 5-year plan for underground distribution in downtown St. John's.

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2011 capital expenditures are in accordance with the Capital Budget Application Guidelines Policy #1900.6 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 B, the Company used the Allowance for Unforeseen Items account to expeditiously deal with events affecting the electrical system which could not wait for Board approval. There was one unforeseen event which required the use of the Allowance for Unforeseen Items account in 2011; an unforeseen expenditure of $305,000 was required in September 2011 to respond to a fault in an underground oil-filled high voltage switch at the intersection of Water Street and McBride's Hill in downtown St. John's. The fault and resulting fire destroyed the switch. Due to peak loading concerns, the switch was replaced before the onset of winter season. A report entitled *McBride's Hill Switch Replacement – January 2012* was submitted to the board on February 2, 2012.

- 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 3.25% in 2010 and (2.73%) in 2011 resulting in no additional reporting requirements.

Capital Expenditure Reports

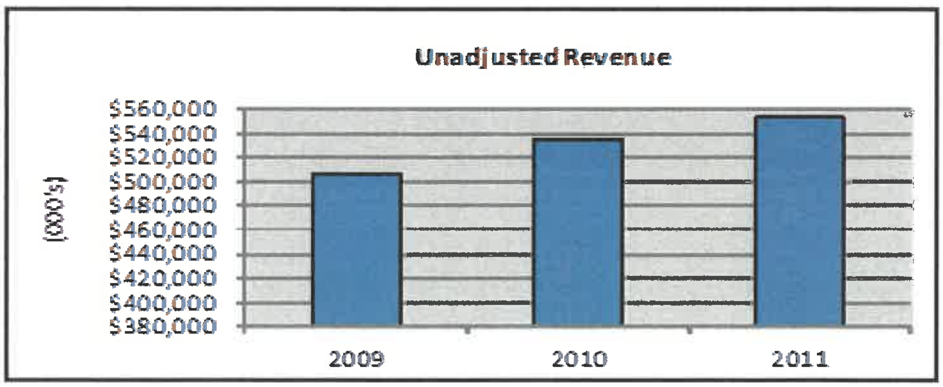
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2011 calendar year.

Revenue

Scope: ***Review the Company's 2011 revenue in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues for 2009 to 2011 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2009	2010	**2011**
Residential	$ 309,360	$ 332,664	**$ 344,609**
General services			
0-10kW	11,840	12,331	**12,568**
10-100kW	63,318	65,291	**67,341**
110-1000kW	74,182	77,976	**79,954**
Over 1000kW	31,675	31,037	**31,500**
Street lighting	12,862	13,540	**13,867**
Forfeited discounts	2,644	2,494	**2,719**
Revenue from rates	$ 505,881	$ 535,333	**$ 552,558**
Year over year percentage change	1.71%	5.82%	**3.22%**



The above graph demonstrates that the Company has seen a 3.22% increase in revenue from rates in 2011 as compared to 2010. Contributing to this increase is an increase in customer rates of 0.76%, which became effective on January 1, 2011. In addition, there was an increase in residential demand as Gigawatt hours sold increased by 2.89% primarily due to an increase of 1.70% in the average number of monthly residential customers.

The comparison by rate class of 2011 actual revenues to 2011 budget is as follows:

(000's)	Actual 2010	Actual 2011	Plan 2011	Actual - Plan Variance	%
Residential	$ 332,664	$ 344,609	$ 338,853	$ 5,756	1.70%
General service					
0-10kW	12,331	12,568	12,229	339	2.77%
10-100kW	65,291	67,341	66,611	730	1.10%
110-1000kW	77,976	79,954	79,462	492	0.62%
Over 1000kW	31,037	31,500	32,233	(733)	-2.27%
Street lighting	13,540	13,867	13,702	165	1.20%
Forfeited discounts	2,494	2,719	2,744	(25)	-0.91%
Total revenue from rates	$ 535,333	$ 552,558	$ 545,834	$ 6,724	1.23%

We have also compared the 2011 energy sales in GWh to those budgeted for 2011.

	Actual 2010	Actual 2011	Plan 2011	Actual - Plan Variance	%
Residential	3,311.2	3,407.0	3,343.7	63.3	1.89%
General service					
0-10kW	92.5	93.7	90.7	3.0	3.31%
10-100kW	649.3	665.5	654.7	10.8	1.65%
110-1000kW	910.6	927.7	923.7	4.0	0.43%
Over 1000kW	419.2	422.4	431.5	(9.1)	(2.11%)
Street lighting	36.2	36.5	35.7	0.8	2.24%
Total energy sales	5,419.0	5,552.8	5,480.0	72.8	1.33%

As can be seen from the above tables, actual revenue from rates increased by $6,724,000 (1.23%) from the 2011 Plan, primarily due to an increase in the average use of electricity by customers as there was a 1.33% increase in GWh sold in 2011 compared to Plan for 2011. The largest variance can be seen in the residential rate class where actual revenues and energy sales increased by $5,756,000 (1.70%) and 63.3 GWh (1.89%) 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.***

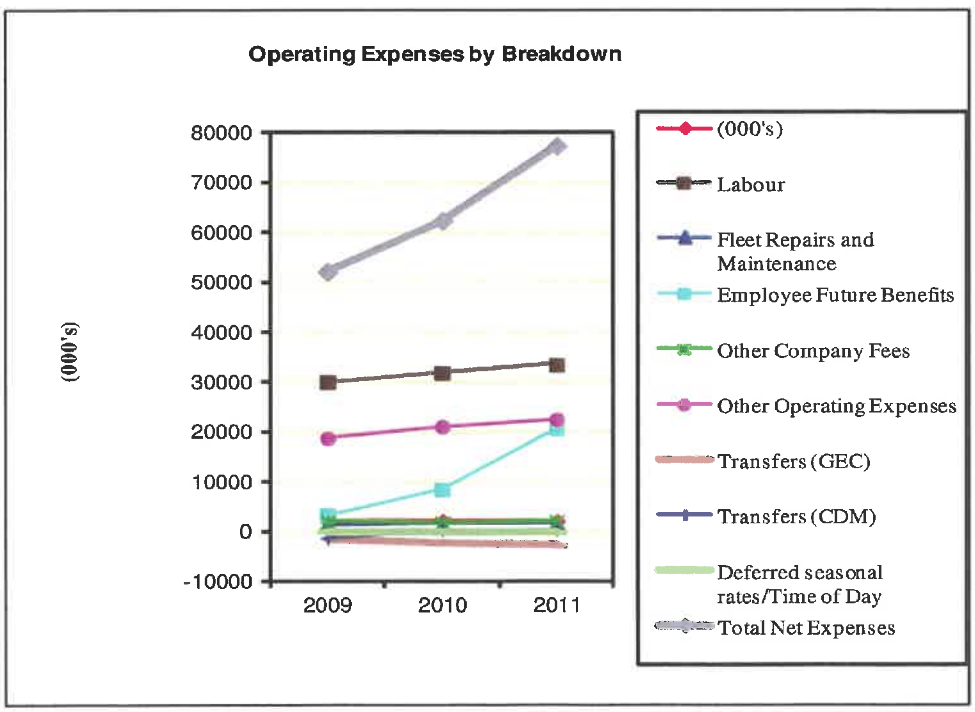
(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011 - 2010
Labour	$ 33,844	$ 32,531	$ 30,518	$ 1,313
Reclass OPEB labour cost	(493)	(793)	(610)	300
Total labour	33,351	31,738	29,908	1,613
Vehicle expense	1,779	1,504	1,436	275
Operating materials	1,533	1,271	1,156	262
Inter-company charges	1,277	1,043	726	234
Plants, Subs, System Oper & Bldgs	1,993	1,814	1,907	179
Travel	1,282	1,124	1,016	158
Tools and clothing allowance	1,031	1,139	1,106	(108)
Miscellaneous	1,468	1,703	1,535	(235)
Conservation	2,184	654	306	1,530
Taxes and assessments	895	706	765	189
Uncollectible bills	1,204	801	934	403
Insurances	1,082	1,094	1,043	(12)
Retirement allowance	164	712	120	(548)
Education, training, employee fees	318	246	215	72
Trustee and directors' fees	399	387	414	12
Other company fees	1,926	1,692	1,950	234
Deferred regulatory costs	253	453	201	(200)
Stationery & copying	302	299	267	3
Equipment rental/maintenance	629	773	683	(144)
Communications	3,086	3,009	2,870	77
Advertising	906	1,287	1,079	(381)
Vegetation management	1,612	1,672	1,459	(60)
Computing equipment & software	774	799	801	(25)
Total other	26,097	24,182	21,989	1,915
Pension and early retirement program	11,566	7,588	2,673	3,978
OPEB's	9,003	793	610	8,210
Total employee future benefits	20,569	8,381	3,283	12,188
Total gross expenses	$ 80,017	$ 64,301	$ 55,180	$ 15,416
Transfers (GEC)	(2,914)	(2,429)	(1,836)	(485)
Transfers (CDM)	339	339	(1,356)	-
Deferred seasonal rates/Time of Day	(258)	-	-	(258)
Total net expenses	$ 77,184	$ 62,211	$ 51,988	$ 14,673

The above table provides details of operating and general expenses by "breakdown" for 2009, 2010 and 2011.

Net operating expenses in 2011 increased by $14,673,000 from 2010. The increase is primarily due to an increase in labour, conservation, pension and early retirement program costs and OPEBs. These and other 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 2011 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 shows the trend in operating expenses by breakdown for the period 2009 to 2011.

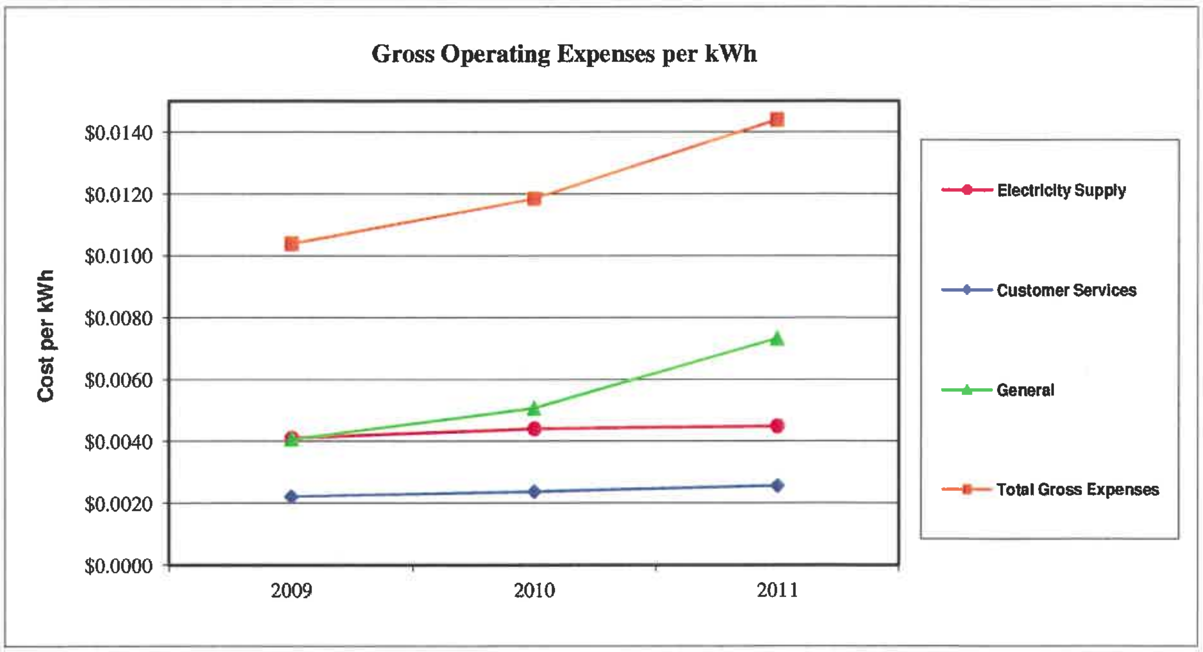
	Actual		
(000's)	**2009**	**2010**	**2011**
Labour	$ 29,908	$ 31,738	**$ 33,351**
Fleet Repairs and Maintenance	1,436	1,504	**1,779**
Employee Future Benefits	3,283	8,381	**20,569**
Other Company Fees	1,950	1,692	**1,926**
Other Operating Expenses	18,603	20,986	**22,392**
Transfers (GEC)	(1,836)	(2,429)	**(2,914)**
Transfers (CDM)	(1,356)	339	**339**
Deferred seasonal rates/Time of Day	-	-	**(258)**
Total Net Expenses	$ 51,988	$ 62,211	**$ 77,184**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2009 to 2011 is presented in the table below.

Comparison of Gross Operating Expenses to Total kWh Sold

		Electricity Supply		Customer Services		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
2009	5,299,000	$ 21,810	$0.0041	$ 11,789	$0.0022	$ 21,581	$0.0041	$ 55,180	$0.0104
2010	5,419,000	$ 23,946	$0.0044	$ 12,872	$0.0024	$ 27,483	$0.0051	$ 64,301	$0.0119
2011	5,552,800	$ 25,009	$0.0045	$ 14,253	$0.0026	$ 40,755	$0.0073	$ 80,017	$0.0144



The table and graph show that total gross expenses per kWh have increased by approximately 21% compared to 2010. This increase is largely due to the increase in the Company Pension Plan costs and the accrual of OPEB's.

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 2009 to 2011 is as follows:

	Actual 2011	Plan 2011	Actual 2010	Actual 2009	Actual Plan 2011	Actual 2011-2010
Executive Group	**7.0**	**7.0**	7.0	8.0	-	-
Corporate Office	**17.9**	**18.1**	19.0	18.4	(0.2)	(1.1)
Finance	**71.2**	**72.3**	68.2	67.2	(1.1)	3.0
Engineering and Operations	**413.3**	**420.9**	408.5	407.8	(7.6)	4.8
Customer Relations	**62.9**	**70.1**	69.3	70.9	(7.2)	(6.4)
	572.3	**588.4**	572.0	572.3	(16.1)	0.3
Temporary employees	**67.8**	**58.7**	68.6	72.2	9.1	(0.8)
Total	**640.1**	**647.1**	640.6	644.5	(7.0)	(0.5)
Year over year percentage change	**(0.08%)**	-	(0.60%)	2.60%		

The overall number of FTE's in 2011 compared to 2010 decreased by 0.5. The budgeted number of FTE's in 2011 was 647.1 versus actual of 640.1. The variance between 2011, 2011 Plan and 2010 are the result of the following:

- The Corporate Office decreased compared to 2010 as a result of a resignation offset by a new hire and an employee splitting their time between Energy Conservation and Corporate Relations.
- Finance increased compared to 2010 as a result of the full year impact of a new Manager who was hired part way through 2010, an employee transferred from Engineering, two new hires and an employee returning from LTD. 2011 Actual is below 2011 Plan as a result of three resignations and a retirement, offset by four new hires.
- Engineering and Operations costs are above 2010 as a result of five temporary employees becoming permanent. 2011 Actual is below 2011 Plan as a result of eighteen retirements, ten resignations, nine employees on LTD, six employees on WCC, an employee on leave of absence, and an employee on maternity leave, offset by thirty-six new hires and employees transferred from Customer Relations.
- Customer Relations decreased from 2010 and 2011 Plan as a result of one retirement, five resignations, five employees on LTD, employees transferred to other departments, offset by a new hire.
- Temporary Employee costs for 2011 are above 2011 Plan as a net result of requirements to replace regular employees on temporary assignments to other departments, LTD, WCC, and other leaves.

An analysis of salaries and wages by type of labour and by function from 2009 to 2011 is as follows:

(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Type				
Internal labour	$ 54,158	$ 52,601	$ 50,925	$ 1,557
Overtime	5,758	6,146	3,849	(388)
	59,916	58,747	54,774	1,169
Contractors	9,743	10,443	9,990	(700)
	$ 69,659	$ 69,190	$ 64,764	$ 469
Function				
Operating	$ 33,844	$ 32,531	$ 30,518	$ 1,313
Capital and miscellaneous	35,815	36,659	34,246	(844)
Total	$ 69,659	$ 69,190	$ 64,764	$ 469
Year over year percentage change	0.68%	6.83%	7.74%	

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 2011 were $469,000 (0.68%) higher than 2010.

Internal labour costs in 2011 were higher than 2010 by 2.96% due to normal salary increases and higher costs relating to employee training and illness.

Overtime for 2011 was lower than 2010 due to additional overtime in 2010 for storm damage (March ice storm and Hurricane Igor) partially offset by additional work associated with the December wind storm in 2011.

Contractors are used to supplement the Company's work force during peak periods of construction. The decrease in contract labour from 2010 was due to storm damage related work in 2010, partially offset by contractor costs for the 2011 pole survey.

Operating labour for 2011 was higher than 2010 due to normal salary increases and higher costs relating to employee training and illness partially offset by the decreased overtimes and contractor costs associated with storm damage.

Capital and miscellaneous labour for 2011 was lower than 2010 primarily due to storm damage work completed in 2010, offset by normal salary increases and contractor costs for the 2011 pole survey.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 2009 to 2011 are included in the table below:

(000's)	Salary Cost Per FTE Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Total reported internal labour costs	$ **54,158**	$ 52,601	$ 50,925	$ 1,557
Benefit costs (net)	**(6,909)**	(7,118)	(6,626)	209
Other adjustments	**(531)**	(554)	(546)	23
Base salary costs	**46,718**	44,929	43,753	1,789
Less: executive compensation	**(1,690)**	(1,555)	(1,879)	(135)
Base salary costs (excluding executive)	$ **45,028**	$ 43,374	$ 41,874	$ 1,654
FTE's (including executive members)	**640.1**	640.6	644.5	
FTE's (excluding executive members)	**636.1**	636.6	639.5	
Average salary per FTE	**72,986**	70,135	$ 67,887	
% increase	**4.06%**	3.31%	3.70%	
Average salary per FTE (excluding executive members)	**70,787**	68,133	$ 65,480	
% increase	**3.90%**	4.05%	3.41%	

The above analysis indicates that for 2011 the rate of increase in average salary per FTE has been fairly consistent from 2009 to 2011. Average salary per FTE is also fairly consistent with 2010. The Company has noted that the 3.90% increase in average salary per FTE (excluding executive members) is primarily due to negotiated salary increases for union employees and annual increases for managerial employees.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2009 to 2011 and the targets set for 2011:

Measure	Target 2011	Actual 2011	Actual 2010	Actual 2009
Controllable Operating Costs/Customer	**$218.0**	$214.2	$215.8	$206.7
Earnings	**32.0m**	33.7m	35.0m	32.6m
Reliability - Duration of Outages (SAIDI)	**2.60**	2.57	2.59	2.50
Customer Satisfaction - % Satisfied	**89.0%**	88.5%	89.3%	89.5%
Customer Satisfaction - 1st Call Resolution	**89.0%**	88.5%	88.3%	88.4%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	**1.7**	1.8	1.9	1.2

The 2011 STI results were adjusted to remove the impact of the wind storm in December, new regulations associated with PCB bushing replacement and special insulation program. The 2010 STI results for the calculation of controllable costs per customers, SAIDI and First Call Resolution were adjusted to remove the impact of the March sleet storm and Hurricane Igor. The Company's STI program also includes an individual performance measure for Executives and Managers. 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%
Other Executives	50%	50%
Managers	50%	50%

The individual measures of performance for Managers 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 2011 is established as a percentage of base pay for the three employee groups. For 2011, measures related to 'earnings', 'controllable operating costs/customers', and 'SAIDI' metrics were met, however, the 'safety' and two '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 2009 to 2011:

STI Payout

	Target 2011	Actual 2011	Target 2010	Actual 2010	Target 2009	Actual 2009
President	**50%**	**63.6%**	40%	54.1%	40%	52.7%
Executive	**35-40%**	**48.2%**	30%	40.3%	30%	40.3%
Managers	**15%**	**16.9%**	15%	18.1%	15%	19.2%

STI actual payout rates for the President and the Executive categories are higher than in the prior year, and the Manager category decreased.

In dollar terms, the STI payouts for 2009 to 2011 are as follows:

	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
President	**$ 245,000**	$ 200,000	$ 195,000	$ 45,000
Executive [1]	**345,000**	280,000	292,000	65,000
Managers [2]	**245,200**	226,800	239,500	18,400
Total	**$ 835,200**	$ 706,800	$ 726,500	$ 128,400
Year over year percentage change	**18.17%**	-2.71%	17.52%	

Note 1: The 2009 results for STI paid to executives were adjusted to remove the impact of amounts paid to the Vice President, Customer and Corporate Services. This position was vacated effective January 12, 2010
Note 2: Managers category includes ten payouts for nine positions (two managers prorated based on time worked as Manager during the year)

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In 2011, the non-regulated portion (before tax adjustment) was $26,400 (2010 - $104,500).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2009 to 2011.

	Base Salary	Short Term Incentive	Other	Total
2011				
Total executive group	$ 1,100,319	$ 590,000	$ 127,325	$ 1,817,644
Average per executive (4)	**$ 275,080**	**$ 147,500**	**$ 31,831**	**$ 454,411**
2010				
Total executive group	$ 1,064,994	$ 480,000	$ 169,207	$ 1,714,201
Average per executive (4)	**$ 266,249**	**$ 120,000**	**$ 42,302**	**$ 428,550**
2009				
Total executive group	$ 1,102,106	$ 487,000	$ 114,258	$ 1,703,364
Average per executive (4)	**$ 275,527**	**$ 121,750**	**$ 28,565**	**$ 425,841**
% Average increase 2011 vs 2010	**3.32%**	**22.92%**	**(24.75%)**	**6.03%**

Note: The 2009-2010 results for executive compensation were adjusted to remove the impact of amounts paid to Vice President, Customer and Corporate Services. This position was vacated effective January 12, 2010

Base salary for the executive group increased from 2010 due to salary increases approved by the Board of Directors. The decrease in the total executive group relating to other compensation in 2011 versus 2010 was due to a $46,437 lump-sum vacation payment made to the President in fiscal 2010. Base salaries have been agreed to the 2011 Board of Directors' minutes, and STI payouts have been agreed to the 2012 Board of Directors' minutes.

Company Pension Plan

For 2011, we reviewed the accounts supporting the gross charge of $11,566,000 for the pension expense accounts of the Company. A detailed comparison of the components of pension expense for 2009 to 2011 is as follows:

	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Pension expense per actuary	**$10,056,965**	$ 6,173,359	$ 1,339,267	$ 3,883,606
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**444,163**	457,459	452,802	(13,296)
Group RRSP @ 1.5%	**467,000**	475,758	486,002	(8,758)
Individual RRSP's	**616,000**	533,262	464,516	82,738
Less: Refunds (net of other expenses)	**(18,128)**	(51,484)	(69,360)	33,356
Total	**$ 11,566,000**	$ 7,588,354	$ 2,673,227	$ 3,977,646
Year over year percentage change	52.42%	183.86%	(12.05%)	

Overall, pension expense for 2011 is higher than 2010 primarily due to a decrease in the discount rate used to determine the Company's accrued defined benefit pension obligation, as well as the amortization of 2008 experience losses associated with pension plan assets. The discount used in 2010 was 6.50% compared to 5.75% in 2011.

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 P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses decreased by 2.9% in 2011.

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. The increase of approximately $74,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2010 was primarily the result of wage increases.

Retirement Allowance

The retirement allowance costs incurred by the Company over the period from 2009 to 2011 are as follows:

(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Terminations and Severance	**$ 154**	$ 501	$ -	$ (347)
Normal Retirements	**-**	240	117	(240)
Other Retiring Allowance Costs	**10**	(29)	3	39
Total	**$ 164**	$ 712	$ 120	$ (548)
Year over year percentage change[1]	-76.97%	493.33%	(61.04%)	

[1] The Retirement Allowance presentation for 2010 is consistent with 2009. In 2011, retirement allowances were included as a part of the OPEBs expense upon adoption of the accrual accounting for OPEBs as specified in P.U. 31(2010).

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 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.

A detailed analysis of the components of the 2011 OPEBs expense is as follows:

	(000's)
2011 accrued OPEBs	$ 5,895
Amortization of transitional balance	3,504
Amount capitalized	(373)
Future income taxes	(23)
	$ 9,003

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) and P.U. 43 (2009);
- compared intercompany charges for the years 2009 to 2011 and investigated any

unusual fluctuations;

- reviewed detailed listings of charges for 2011 and investigated any unusual items;
- vouched a sample of transactions for 2011 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 2009 to 2011 for charges to and from Newfoundland Power Inc.:

	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Charges from related companies				
Regulated	$ **130,719**	$ **318,344**	$ 148,141	$ (187,625)
Non-Regulated	**1,602,265**	**1,404,293**	1,083,521	197,972
Total	**1,732,984**	**1,722,637**	1,231,662	10,347
Charges to related companies	$ **913,593**	$ **956,364**	$ 885,053	$ (42,771)

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 2011.

- Fortis Inc. estimated its net pool of operating expenses for 2011 in Q4 2010 as part of its annual business planning process 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 evenly based upon 25% of the estimated annual amount.
- Similar to 2010, certain staffing and staffing related charges, as well as certain consulting and legal fees, were included in the pool of recoverable expenses. Of these expenses, Fortis deemed 50% of the CEO's and CFO's salary and related costs to be borne by Fortis Inc. for business development and consequently is excluded from the pool of recoverable expenses. Additionally, certain consulting and legal fees that are attributable to business acquisition activity are excluded. This is consistent with 2010.
- Fortis Inc. used actual year-to-date expenditures up to October and estimated November and December's expenses for the determination of its actual 'true up' calculation. Fortis also used actual assets at September 30, 2011 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of November and December's expenditures had a minimal impact.

During the fourth quarter of 2011, a true-up calculation was completed to reflect actual recoverable expenses which were determined to be $1,277,000 and are summarized as follows:

2011 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$ 574,000	Non-regulated
Director Fees	143,000	Non-regulated
Consulting and Legal fees	133,000	Non-regulated
Trustee Agent Fees	51,000	Regulated
Audit and Other Fees	46,000	Non-regulated
Public Reporting Costs	71,000	Non-regulated
Annual Meeting Expenses	42,000	Non-regulated
Travel (Board and Other)	57,000	Non-regulated
Insurance (D&O)	46,000	Non-regulated
Other Costs	114,000	Non-regulated
	1,277,000	
Less amounts previously billed:		
Q1 2011	293,000	
Q2 2011	293,000	
Q3 2011	293,000	
Q4 2011 balance owing	$ 398,000	

For 2011, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 10.43%, relatively unchanged from 10.42% in 2010.

As detailed above, trustee agent fees for $51,000 was the only expense 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, e.g. Non-Joint Use Poles charges and miscellaneous charges.

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 2009 to 2011 with Fortis Inc.:

Intercompany Transactions (Regulated)	**Actual 2011**	**Actual 2010**	**Actual 2009**	**Variance 2011-2010**
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 51,000**	$ 45,000	$ 42,000	$ 6,000
Miscellaneous	**7,629**	12,493	35,862	(4,864)
Non-Joint Use Poles	**11,566**	13,512	2,532	(1,946)
	$ 70,195	$ 71,005	$ 80,394	$ (810)
Year over year percentage change	**-1.14%**	-11.68%	-52.91%	
Charges to Fortis Inc.				
Postage and couriers	**$ 22,263**	$ 20,851	$ 20,689	$ 1,412
Printing, stationery and materials	-	-	129	-
IS charges	-	-	277	-
Staff charges	**299,786**	500,948	327,534	(201,162)
Staff charges - insurance	**179,005**	213,164	173,887	(34,159)
Pole removal and installation	**20,191**	23,976	23,599	(3,785)
Miscellaneous	**92,974**	8,747	11,969	84,227
	$ 614,219	$ 767,686	$ 558,084	$ (153,467)
Year over year percentage change	**-19.99%**	37.56%	5.75%	

The most significant fluctuation from our analysis of regulated intercompany charges for 2011 compared to 2010 related to staff charges. These charges to Fortis Inc. decreased by $201,162 from 2010 primarily due to less Newfoundland Power staff involvement in potential Fortis Inc. acquisition projects compared to 2010. There was also a reduction in the pole maintenance work that Newfoundland Power completed on the Fortis owned non-joint use poles as a result of the sale of these poles to Bell Aliant. Staff charges related to insurance decreased $34,159 compared to 2010 primarily due to the timing effect of including both 2009 and 2010 payments for Fortis' Risk Manager in 2010. Miscellaneous charges have increased $84,227 compared to 2010 as a result of a onetime charge of $81,802 which represents Fortis' share of the pole survey costs relating to the sale of poles to Bell Aliant.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2009 to 2011:

(Non-Regulated)	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Charges from Fortis Inc.				
Director's fees and travel	$ **200,000**	$ 263,000	$ 226,000	$ (63,000)
Annual and quarterly reports	**117,000**	89,000	91,000	28,000
Staff charges	**574,000**	352,000	71,000	222,000
Miscellaneous	**711,265**	697,877	695,521	13,388
	$ **1,602,265**	$ 1,401,877	$ 1,083,521	$ 200,388
Year over year percentage change	**14.29%**	29.38%	18.02%	

The most significant variances from our above analysis of non-regulated intercompany charges for 2011 compared to 2010 are as follows:

- Director's fees and travel expenses decreased by $63,000. The 24% decrease is due to the impact from the change in Fortis' share price year over year. This has a direct impact on the costs associated with the Company's Directors' Deferred Share Unit (DDSU) Plan.

- Staff charges for 2011 have increased by $222,000. Fortis Inc. does not recover a portion of its salaries and benefits related to business development activities. The 63% increase is mainly due to the loss of ancillary income from the sale of Fortis Inc's non-joint use poles to Bell Aliant in December 2010. Prior to the Bell Aliant pole sale, Fortis Inc. would offset recoverable costs with the ancillary rental income generated from non-joint use poles. With the sale of Fortis Inc. poles to Bell Aliant in December 2010, the rental income used to offset allocated staff charges ended. In 2010, the portion of non-joint use pole revenues used to offset staff charges to Newfoundland Power was approximately $150,000.

The following table provides a summary and comparison of the other intercompany transactions for 2009 to 2011:

Intercompany Transactions (Other)	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Charges to Fortis Properties				
Staff charges	$ -	$ 1,247	$ -	$ (1,247)
Staff charges - insurance	37,042	23,303	13,517	13,739
IS charges	-	-	4,432	-
Stationary costs	678	401	714	277
Miscellaneous	2,147	9,745	4,691	(7,598)
	$ 39,867	$ 34,696	$ 23,354	$ 5,171
Charges from Fortis Properties				
Staff charges	$ -	$ -	$ 12,000	$ -
Hotel/Banquet facilities & meals	37,387	69,612	25,627	(32,225)
Miscellaneous	8,029	11,814	4,681	(3,785)
	$ 45,416	$ 81,426	$ 42,308	$ (36,010)
Charges to Fortis Ontario Inc.				
Staff charges - insurance	$ 1,622	$ 4,417	$ 17,688	$ (2,795)
Staff charges	7,065	-	-	7,065
IS charges	3,351	4,788	2,424	(1,437)
Miscellaneous	360	360	273	-
	$ 12,398	$ 9,565	$ 20,385	$ 2,833
Charges to Maritime Electric				
Staff charges	$ 16,296	$ 2,312	$ 1,932	$ 13,984
Staff charges - insurance	2,693	1,346	1,488	1,347
IS charges	4,787	3,351	2,424	1,436
Miscellaneous	550	580	701	(30)
	$ 24,326	$ 7,589	$ 6,545	$ 16,737
Charges from Maritime Electric				
Staff charges	$ -	$ 86,218	$ -	$ (86,218)
Miscellaneous	9,211	7,338	8,977	$ 1,873
	$ 9,211	$ 93,556	$ 8,977	$ (84,345)
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	$ 432	$ 1,134	$ 8,743	$ (702)
Staff charges	-	37,456	86,581	(37,456)
	$ 432	$ 38,590	$ 95,324	$ (38,158)
Charges to Fortis US Energy Corp				
Staff charges - insurance	$ 2,581	$ -	$ -	$ 2,581

Intercompany Transactions (Other) Cont'd.	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Charges to Belize Electricity				
Staff charges	$ -	$ 3,739	$ 11,424	$ (3,739)
IS charges	-	-	4,155	-
Staff charges - insurance	1,296	8,043	8,436	(6,747)
Miscellaneous	1,176	5,177	4,863	(4,001)
	$ 2,472	$ 16,959	$ 28,878	$ (14,487)
Charges to FortisAlberta Inc.				
Staff charges	$ 18,219	$ -	$ -	$ 18,219
Staff charges - insurance	3,365	540	3,456	2,825
Miscellaneous	3,120	2,990	3,441	130
	$ 24,704	$ 3,530	$ 6,897	$ 21,174
Charges from FortisAlberta Inc.				
Staff charges	$ 4,805	$ 64,914	$ -	$ (60,109)
Charges to FortisBC Inc.				
IS charges	$ 13,405	$ 13,405	$ 8,310	$ -
Staff charges - insurance	5,869	1,410	1,620	4,459
Miscellaneous	1,944	1,919	2,203	25
	$ 21,218	$ 16,734	$ 12,133	$ 4,484
Charges from FortisBC Inc.				
Miscellaneous	$ 1,092	$ 9,859	$ 16,462	$ (8,767)
Charges to Fortis BC Holdings				
Staff charges	$ 10,215	$ -	$ -	$ 10,215
Staff charges - insurance	2,983	540	1,296	2,443
Miscellaneous	6,547	6,212	6,425	335
	$ 19,745	$ 6,752	$ 7,721	$ 12,993
Charges to Caribbean Utilities Co. Limited				
Staff charges	$ 6,938	$ -	$ 888	$ 6,938
Staff charges - insurance	21,168	7,452	6,837	13,716
Miscellaneous	-	-	101	-
	$ 28,106	$ 7,452	$ 7,826	$ 20,654
Charges to Fortis Turks and Caicos				
Staff charges	$ 117,504	$ 37,679	$ 103,091	$ 79,825
Staff charges - insurance	5,946	8,255	7,785	(2,309)
Miscellaneous	75	877	7,030	(802)
	$ 123,525	$ 46,811	$ 117,906	$ 76,714

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The most significant fluctuations from our analysis of other intercompany charges for 2011 compared to 2010 are as follows:

- Hotel/Banquet facilities & meals charges from Fortis Properties decreased $32,225 from 2010 due to out-of-town crews staying at the Holiday Inn during Hurricane Igor in 2010.

- Staff charges to Maritime Electric increased $13,984 over 2010 due to the back billing of travel expenses for President & Chief Executive Officer for the period 2008 to 2010.

- Staff charges from Maritime Electric decreased $86,218 from 2010 due to out-of-town crews staying at the Holiday Inn during Hurricane Igor in 2010.

- Staff charges to Belize Electric Company Ltd. decreased $37,456 from 2010. Staff charges in 2010 were related to the participation of Newfoundland Power engineering staff in the construction of a hydro generation project in Belize; there were no such expenses in 2011.

- Staff charges to FortisAlberta Inc. increased by $18,219 due to the participation of a Newfoundland Power staff member on a project involving performance based regulation.

- Staff charges to Fortis BC Holdings were incurred by a Newfoundland Power staff person in support of the implementation of new customer service and billing processes and policies for FortisBC.

- Staff charges – insurance to Caribbean Utilities Co. increased by $13,716 over 2010. The increase in insurance costs was due to risk management staff having to make two trips to the Caribbean Utilities Co in 2011 versus one trip in 2010.

- Staff charges to Fortis Turks and Caicos increased by $79,825 over 2010 due to the participation of a Newfoundland Power engineering staff person in design, project supervision and other activities related to a transmission rebuild project.

In Order 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 2011. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2011.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2010 General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2011 and noted no exceptions.

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 2011 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Other company fees				
Other company fees	**$ 1,749**	$ 1,513	$ 1,468	$ 236
Regulatory hearing costs - other	**178**	179	482	(1)
Total other company fees	**$ 1,927**	$ 1,692	$ 1,950	$ 235
Year over year percentage change	**13.9%**	-13.2%		
Deferred regulatory costs				
Total deferred regulatory costs	**$ 253**	$ 453	$ 201	$ (200)
Year over year percentage change	**(44.2%)**	125.4%	0.5%	

"Regulatory hearing costs – other" are essentially unchanged from 2010. Other company fees in 2011 are higher than 2010 primarily due to increased regulatory costs and fees relating to the conversion to U.S. GAAP. These increases are partially offset by a reduction in CDM costs due to the timing of program delivery, and timing and need for the purchase of oil testing kits. 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 2009 to 2011 is as follows:

(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Miscellaneous	**$ 858**	$ 1,046	$ 777	$ (188)
Cafeteria and lunchroom supplies	**97**	92	79	5
Promotional items	**118**	135	197	(17)
Computer Software	**3**	1	4	2
Damage Claims	**141**	143	196	(2)
Community relations activities	**3**	14	12	(11)
Donations and charitable advertising	**180**	194	193	(14)
Books, magazines and subscriptions	**45**	58	53	(13)
Misc. lease payments	**23**	20	24	3
Total miscellaneous expenses	**$ 1,468**	$ 1,703	$ 1,535	$ (235)
Year over year percentage change	**(13.80%)**	10.94%	14.81%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2010 to 2011 these expenses have decreased by 13.80% overall, primarily because of two specific one-time items recorded in 2010 - the write off of deferred costs relating to the Company's Safety Management System, and work relating to a study of the Company's VHF radio system.

Donations and charitable advertising included in miscellaneous expenses are non-regulated expenses.

Our procedures in this expense category for 2011 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 2011 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2011 Conservation and Demand Management Report with the Board. This report provided a summary of 2011 CDM activities and costs as well as the outlook for 2012. Costs have increased over the prior year mainly due to the increased participation in Energy Savers Programs. Costs in 2011 totaled $4,209,000 compared to $3,260,000 in 2010. Going forward, the Company will continue to promote and encourage participation in its takeCHARGE incentive programs.

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 2011 and 2010 as follows:

(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011 - 2010
Vehicle expense	**1,779**	1,504	1,436	275
Operating materials	**1,533**	1,271	1,156	262
Plants, Subs, System Oper & Bldgs	**1,993**	1,814	1,907	179
Travel	**1,282**	1,124	1,016	158
Tools and clothing allowance	**1,031**	1,139	1,106	(108)
Taxes and assessments	**895**	706	765	189
Uncollectible bills	**1,204**	801	934	403
Insurances	**1,082**	1,094	1,043	(12)
Education, training, employee fees	**318**	246	215	72
Trustee and directors' fees	**399**	387	414	12
Stationary & copying	**302**	299	267	3
Equipment rental/maintenance	**629**	773	683	(144)
Communications	**3,086**	3,009	2,870	77
Advertising	**906**	1,287	1,079	(381)
Vegetation management	**1,612**	1,672	1,459	(60)
Computing equipment & software	**774**	799	801	(25)
Transfers (GEC)	**(2,914)**	(2,429)	(1,836)	(485)
Transfers (CDM)	**339**	339	(1,356)	-

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

- Vehicle expenses increased by $275,000 in 2011 primarily due to increases in fuel costs
- Operating materials increased by $262,000 in 2011. The variance was the result of contracting out streetlight repairs in St. John's
- Systems operations increased by $179,000 in 2011, due to increased snow clearing and building repair costs
- Travel expenditures increased by $158,000 in 2011 due to increases in employee relocation costs.
- Tools and clothing allowance costs were lower by $108,000 in 2011 due to lower utilization of tools, as 2010 included the impact of Hurricane Igor
- Taxes and assessments increased by $189,000 in 2011, as a result of an increase in the annual assessment from the Public Utilities Board.
- Uncollectible bills increased in 2011 by $403,000. The Company indicated that uncollectible bills vary year to year as a result of general economic conditions. Also, 2011 included a provision for the Bell Aliant joint use pole sale amounting to $250,000, to allow for amounts in dispute and differences to settle to close the transaction. The transaction subsequently closed in January, 2012 and was settled with a purchase price adjustment of $800,000. Subsequently, the outstanding receivables were collected.
- Equipment rental and maintenance decreased by $144,000 in 2011. The decrease was directly related to 2010 expenses relating to Hurricane Igor

- Advertising decreased by $381,000 in 2011 due to increased participation in conservation initiatives, reducing the need for additional advertising
- Transfers (GEC) decreased by $485,000 in 2011. This is primarily related to high pension costs

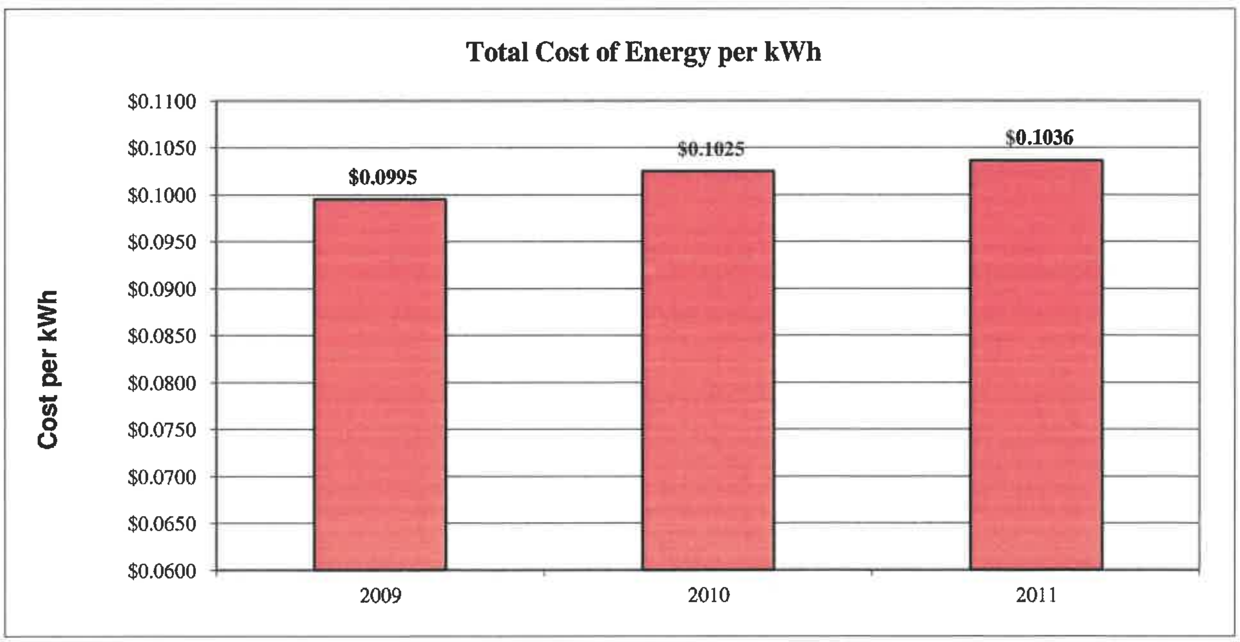
Other Costs

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 2009 to 2011:

		(000's)							
Year	kWh sold	Operating Expenses	Purchased Power	Depreciation	Finance Charges*	Income Taxes	Dividends and Return	Total Cost of Energy	Cost per kWh
2009	5,299,000	$ 51,988	$ 345,656	$ 45,687	$ 34,555	$ 16,092	$ 33,201	$ 527,179	$ 0.0995
2010	5,419,000	$ 62,211	$ 358,443	$ 47,220	$ 36,038	$ 15,870	$ 35,573	$ 555,355	$ 0.1025
2011	5,552,800	$ 77,184	$ 369,484	$ 42,695	$ 35,944	$ 15,876	$ 34,252	$ 575,435	$ 0.1036

* - 2010 Comparative has been restated to reflect 2010 interest charged to construction instead of AFUDC, which included an equity portion. 2009 has not been restated as the external financial statements include only 2011 and 2010 balances.



Purchased Power

We have reviewed the Company's purchased power expense for 2011 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.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the Gannett Fleming Depreciation Study, dated December 31, 2005 and assessed the reasonableness of depreciation expense.

The changes in depreciation rates and policies flowing from the Gannett Fleming Depreciation Study, dated December 31, 2005 were approved by the Board to be effective January 1, 2008 according to P.U. 32 (2007).

The objective of our procedures in this section was to ensure that the 2011 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the Depreciation Study undertaken by Gannett Fleming, Inc. dated December 31, 2005.

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 2011; and,
- assessed the overall reasonableness of the depreciation for 2011.

Amortization expense for 2011 is $42,695,000 as compared to $43,358,000 for 2010, representing a 1.53% decrease. The change is attributable to the sale of poles to Bell Aliant Regional Communication Inc. The sale, which removed assets at a cost of $77,358,443, was approved by Order No. P.U. 21 (2011). The decrease was almost entirely offset by an increase of depreciable assets (approximately $74,784,000).

The Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005. As a result of this study a reserve variance or Amortization True-Up of $695,000 was identified. This amount represents the variances between the calculated accrued depreciation and the book accumulated depreciation which exceeds the 5% tolerance threshold. This balance was approved by the Board to be amortized over four years commencing in 2008.

Gannett Fleming has recommended that the Company continue to use the straight-line equal life group method that it has been using for a number of years for its plant assets with the exception of certain General and Communication accounts. Amortization accounting is considered appropriate for the General and Communication accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts.

In P. U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. However, the Board subsequently ordered, pursuant to P.U.43 (2009) that the Company file its next depreciation study relating to plant in service as of December 31, 2009. The purpose of this change was due to the requirement of the Company to file financial statements in 2011 that are in compliance with International Financial Reporting Standards and require comparative figures for 2010. The study for plant in service as of December 31, 2010 was completed in 2011 and is intended to be dealt with as part of the Company's next GRA filing.

The most recent Amortization Study, based on capital assets in service as at December 31, 2010, indicated an accumulated Amortization True-Up of $17.7 million. Subject to PUB approval, this Amortization True-Up is expected to increase the amortization of capital assets in future years which will be recovered in future customer rates.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006) and P.U. 32 (2007), and the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005 have been incorporated into the Company's depreciation calculations for 2011.

Interest and 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:

(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011 - 2010
Interest				
Long-term debt	**$ 35,444**	$ 35,850	$ 34,547	$ (406)
Other	**702**	334	411	368
Amortization				
Debt discount	**308**	232	235	76
Capital stock issue	**-**	37	37	(37)
Interest charged to construction (Note)	**(510)**	(415)	(675)	(95)
Total finance charges	**$ 35,944**	$ 36,038	$ 34,555	$ (94)
Year over year percentage change	**(0.26%)**	4.29%	3.13%	

Note: 2010 interest charged to construction has been restated to show only the interest portion of AFUDC.

In the above table, the decrease in interest on long term debt compared to 2010 is attributable to the decreasing amount of bonds outstanding.

The increase in other interest reflects changing interest rates on the Company's credit and demand facilities during 2011 compared to 2010.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2011 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2011 and have noted that the effective income tax rate increased from 30.9% in 2010 to 31.7% in 2011. This increase is primarily due to timing of pension funding and the allocation of the Part VI.1 tax liability and related Part 1 tax deduction from Fortis to the Company in 2011. This was offset by the tax treatment of regulatory amortizations, deferral accounts and a reduction in the statutory tax rate of 1.5%.

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 2011 is unreasonable.

Costs Associated with Curtailable Rates

In 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 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 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 of the curtailment credits for 2011 was $302,750 compared to the 2010 credits of $250,203. Total operating costs incurred by the Company in 2011 was $326,253 compared to $277,932. The increase in credits compared to the previous year is primarily a result of the number of successful customer curtailments.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and 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 2011 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2011 and investigated any unusual items;
* 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.

(000's)	2011	2010	2009	2011-2010
Charged from Fortis Companies:				
Annual report	$ **117,000**	$ 89,000	$ 91,000	$ 28,000
Directors' fees and travel	**200,000**	263,000	226,000	(63,000)
Staff charges	**574,000**	354,400	71,000	219,600
Miscellaneous	**711,300**	697,900	695,500	13,400
	1,602,300	1,404,300	1,083,500	198,000
Donations and charitable advertising	**266,300**	305,500	296,200	(39,200)
Executive short term incentive	**26,400**	104,500	113,700	(78,100)
Miscellaneous	**94,100**	109,400	93,700	(15,300)
	1,989,100	1,923,700	1,587,100	65,400
Less: Income taxes	**606,700**	615,500	523,700	(8,800)
Less: Part VI.1 tax adjustment	**(221,300)**	328,900	(139,200)	(550,200)
Total non-regulated (net of tax)	$ **1,603,700**	$ 979,300	$ 1,202,600	$ 624,400

In the table above the most significant fluctuation between 2011 and 2010 pertains to the Part VI.1 tax adjustment. This tax adjustment results from the payment by Fortis of dividends on its preferred shares. The Company has noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.'s corporate tax planning and preferred share dividend payment, and the Company's capacity to cover this tax.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2011 this represents an addition to non-regulated expenses (before tax adjustment) of $26,400 (2010 - $104,500). 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 30.5% which agrees with the Company's statutory rate as identified in the 2011 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 and Deferred Charges

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

Regulatory Assets and Liabilities

The following table summarizes Regulatory Assets and Regulatory Liabilities from 2009 to 2011:

(000's)	Actual 2011	Actual 2010	Actual 2009	Variance 2011-2010
Regulatory Assets				
Rate stabilization account	$ **12,434**	$ 3,723	$ 1,836	$ 8,711
OPEBs asset	**49,056**	52,559	46,713	(3,503)
Weather normalization account	**2,102**	4,204	6,031	(2,102)
Amortization true-up deferral	**-**	-	3,862	-
Pension deferral	**3,665**	4,793	5,921	(1,128)
Cost recovery deferral	**2,363**	-	-	2,363
Replacement energy deferral	**-**	-	600	-
Deferred GRA costs	**253**	506	951	(253)
Conservation and demand management	**678**	1,017	1,357	(339)
Optional seasonal rate revenue and cost recovery account	**328**	-	-	328
Future income taxes	**129,021**	120,327	118,701	8,694
	$ **199,900**	$ 187,129	$ 185,972	$ 12,771
Regulatory Liabilities				
Rate stabilization account	$ **-**	$ -	$ 418	$ -
Municipal tax liability	**-**	-	1,363	-
Unbilled revenue liability	**-**	-	4,618	-
Weather normalization account	**9,108**	6,892	-	2,216
Purchased power unit cost variance reserve	**-**	-	688	-
Future removal and site restoration provision	**49,754**	49,485	48,660	269
Demand management incentive account	**1,801**	994	-	807
	$ **60,663**	$ 57,371	$ 55,747	$ 3,292

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, 2011 were approved by the Board in P.U.12 (2011). The RSA regulatory asset of $12,434,000 represents a current portion of $8,571,000 and a non-current portion of $3,863,000.

As of December 31, 2011, there was a charge to the RSA of $6,895,400 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007) and P.U. 43 (2009).

Pursuant to 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, 2011, the credit balance of $2,887,535 in the PEVDA account was credited to the RSA in accordance with P.U. 43 (2009).

Pursuant to 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, 2011, the credit balance of $194,940 in the OPEBVDA account was credited to the RSA in accordance with P.U. 31(2010).

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"). Total benefits paid in 2011 were $2,200,000 compared to a net benefits expense under accrual accounting of $(1,304,000). In P.U. 43 (2009) the Board ordered the continuation of recording OPEBs on the cash basis and that the Company file with the Board 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 P.U. 31(2010).

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. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year. As at December 31, 2011, the non-reversing Degree Day component is a regulatory asset in the amount of $2,102,000 (2010 - $4,204,000) inclusive of future income tax. The balance in the Weather Normalization reserve represents the reversing component, which should tend to zero over time. As at December 31, 2011, the reversing component is a regulatory liability in the amount of $9,108,000 (2010 – $6,892,000 netted in regulatory asset). The net balance in the Weather Normalization reserve at December 31, 2011 is a net regulatory liability of $7,006,000 (net of future income taxes, the balance is $5,020,000).

The Amortization True-up Deferral (formerly known as the Depreciation True-up Deferral) was created to extend the impact of the Amortization True-up that arose from the Company's 2002 amortization study. In P.U. 32 (2007) the Board approved the Company's proposal to amortize the balance as at December 31, 2007 of $11,586,000 over a three year period commencing in 2008. The balance was fully amortized as at December 31, 2010.

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004).

The Cost Recovery Deferral balance relates to the conclusion of the following regulatory amortizations which expired in 2010: 2005 Unbilled Revenue; Municipal Tax Liability, Depreciation, Replacement Energy; Purchased Power Unit Cost Reserve and 2008 GRA Costs. Expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000. On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of the above mentioned deferrals. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 46(2009). In P.U. 30 (2010), the Board approved the deferred recovery, until a further Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which is to be charged with the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differ from the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. The disposition of the $2,363,000 balance in this account will be determined by a further order of the Board.

The Replacement Energy Deferral account is related to the deferral of replacement energy costs associated with the Company's refurbishment of the Rattling Brook hydroelectric plant. P.U. 32 (2007) approved the amortization of $1,147,000 over a three year period which commenced in 2008. The balance was fully amortized as at December 31, 2010.

As noted in the 2010 Annual Review Report, the Company deferred $760,000 of costs relating to the 2010 GRA. According to P.U. 43 (2009) the Board approved the amortization of a total amount of $750,000 over a three year period commencing January 1, 2010 and in P.U. 26 (2011) the Board ordered Newfoundland Power to adjust its 2011 rate base with respect to the recovery of hearing costs recorded in 2010 to reflect the originally approved $750,000. Newfoundland Power adjusted its rate base.

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 P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In 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.

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2011 was $328,006. This balance was transferred to the RSA on March 31, 2012 pursuant to the Board's approval in P.U. 10 (2012).

Pursuant to the amendment of CICA Handbook section 3465, commencing 2009 the Company was required to recognize future income tax assets and liabilities as well as offsetting regulatory assets and liabilities. This amendment does not affect the company's earnings or cash flows.

The Municipal Tax Liability account results from a timing difference related to the recovery and payment of municipal taxes. P.U. 32 (2007) approved the amortization of $4,087,000 over a three year period which commenced in 2008. The balance was fully amortized as at December 31, 2010.

The Unbilled Revenue Liability account arose due to the Company's transition from recognizing revenue on a billed basis to an accrual basis in 2006. The balance represents the unamortized balance of this account as of December 31, 2009. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of

$13,854,000 over a three year period, which commenced in 2008. The remaining balance of $4,618,000 was fully amortized in 2010.

The Purchased Power Unit Cost Variance Reserve account was created to limit variations in the cost of purchased power associated with a demand and energy wholesale rate structure. This account was discontinued effective January 1, 2008 pursuant to P.U. 32 (2007) and replaced with the Demand Management Incentive Account. In P.U. 32 (2007), the Board approved the amortization of the 2006 balance of $1,342,000 in after tax costs over a three year period which commenced in 2008. This amount was fully amortized in 2010.

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchase power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2011, the variation in the account was $1,801,000. This balance was transferred as a credit to the RSA on March 31, 2012 pursuant to the Board's approval in P.U.9 (2012).

The Future Removal and Site Restoration Provision account represents estimated costs to be incurred in the future related to the removal of capital assets.

Deferred Charges

The table below summarizes changes made to deferred charges during 2011 as summarized by the Company in Return 8 of its annual return.

(000's)	Balance December 31 2010	Additions During 2011	Reductions During 2011	Balance December 31 2011
Deferred pension costs[1]	$ 102,549	$ 5,137	$ (10,058)	**$ 97,628**
Deferred credit facility issue costs	258	130	(118)	**270**
Average rate base	$ 102,807	$ 5,267	$ (10,176)	**$ 97,898**

[1] Deferred Pension Costs December 31, 2011 balance includes $3.7 million in pension costs associated with the 2005 Early Retirement Program. Theses pension costs were originally $11.3 million and are being amortized over 10 years, beginning April 1, 2005.

Deferred pension costs include $3,665,000 related to a pension deferral which is included with Regulatory Assets in the Company's financial statements as discussed earlier in the report. The net change in this account represents the difference between employer contributions and pension expense during 2011.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges and regulatory deferrals for 2011 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account (PEVDA) and assess compliance with P.U. 43 (2009)***

In P.U. 43 (2009) the Board approved the creation of the Pension Expense Variance Deferral Account (PEVDA). 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 2011 PEVDA was calculated at $2,887,535. This balance was transferred to the rate stabilization account in March, 2011. In 2010, it was determined that the amount calculated for 2010 was overstated by $70,310. This error was due to the calculation of the variance being prepared using gross defined benefit pension expense instead of the defined benefit pension expense (net of GEC). This overstatement was a benefit to customers and was not corrected by Newfoundland Power. The 2011 calculation was prepared using the defined benefit pension expense (net of GEC).

We confirm that the 2011 PEVDA is calculated in accordance with P.U. 43 (2009).

Other Post Employment Benefits Cost Variance Deferral

Scope: ***Review the calculation of the Other Post Employment Benefits Cost Variance Deferral Account (OPEBVDA) and assess compliance with P.U. 31(2010)***

In P.U. 31 (2010) the Board approved the creation of the Other Post Employment Benefits Cost Variance Deferral Account (OPEBVDA). OPEBVDA was created to capture the difference between the annual OPEB expense approved for the test year revenue requirement and the actual OPEB 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 OPEB 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 2011 OPEBVDA was calculated at $195,000. This balance was transferred to the Rate Stabilization Account on March 31, 2011 in accordance with P.U. 31 (2010).

We confirm that the 2011 OPEVDA is calculated in accordance with P.U. 31 (2010).

Optional Seasonal Rate Revenue and Cost Recovery Account

Scope: ***Review of calculation of the Optional Seasonal Rate Revenue and Cost Recovery Account and assess compliance with P.U. 8 (2011)***

In P.U. 8 (2011) the Board approved Rate #1.1S Domestic Seasonal – Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates (the "TOD Rate Study"). On December 31st of each year from 2011 until further order of the Board, this account is to 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 accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the 1st day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. It was noted by the Company that the filing deadline of March 1, 2012 was missed due to an administrative error. The application was subsequently filed by the Company on March 30, 2012.

The Optional Seasonal Rate Revenue and Cost Recovery Account balance at December 31, 2011 was $328,006. This balance was transferred to the Rate Stabilization Account in March, 2012 as approved in P.U. 10 (2012).

We confirm that the 2011 Optional Seasonal Rate Revenue and Cost Recovery Account is calculated in accordance with P.U. 8 (2011). The deadline for filing an application for the disposition of the balance in this account was March 1, 2012; the Company did not file the application until March 30, 2012 due to an administrative error.

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 2011 are as follows:

1. The Company continued with mobile technologies projects, installing computers in additional trucks in the fleet.

2. Maintained a Power Line Technician Apprentice Program to facilitate transfer of critical knowledge from senior employees.

3. Replaced over 400 hundred transformers with stainless steel units.

4. The Company eliminated 11 meter reading routes in Paradise, Conception Bay South and St. Mary's Bay. An additional route was eliminated in St. John's for an overall total of 12.

5. Upgraded phone technology in the Consumer Contact Centre to Voice Over Internet Protocol (VOIP) technology extending the life of the system and provided a reduction in monthly telephone charges for the Customer Contact Centre.

6. Launched a version of the Company's web site adapted for use on mobile phones.

7. The Company implemented "Click" scheduling software to organize and schedule work for service and line crews in St. John's Regional Operations. This software matches work to crews based on location and skill set, optimizing field work and reducing administrative effort.

8. Engineering Technologists started using Blackberry technology to update customer work orders in the field with work planning details, such as customer contact information, GPS coordinates and job notes, rather than update the system from field notes after returning to the office. This work order planning information is then made available to crews through the "Click" system.

9. The Company participated in a Provincial government working group on energy conservation planning. Two ongoing projects include modeling of energy efficiency program impacts in the Province, as well as a review of Canadian commercial/industrial programs.

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.

1 The following table lists the principal performance measures used in the management of the company:
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Category	Measure	Actual 2009	Actual 2010	Actual 2011	Plan 2011	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.57	2.59	2.57	2.60	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.99	1.52	1.70	1.95	Yes
	Plant Availability (%)	96.9	96.8	93.5	96.5	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	89.5	89.3	88.5	89.0	No
	Call Centre Service Level (% per second)[2]	76/40	78/60	80/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	90.8	82.7	80.2	85.0	No
Safety	All Injury/Illness Frequency Rate	1.2	1.9	1.8	1.7	No
Financial	Earnings (millions)	$33.2	$35.0	$33.7	$32.0	Yes
	Gross Operating Cost/Customer[3]	$214	$234	$241	$225	No

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[1] 2011 reliability statistics reported above exclude the impact of a storm in December. 2010 reliability statistics exclude the impact of the March 2010 ice storm and Hurricane Igor.
[2] In 2010, Customer Service changed how it monitors answered calls. Service level is now based on calls answered in 60 seconds as opposed to 40 seconds in the original plan.
[3] Excluding pension, OPEBs and early retirement costs.

Grant Thornton
2012 Annual Financial Review of Newfoundland Power Inc.

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Board of Commissioners of Public Utilities
2012 Annual Financial Review of Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2012 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 2012 was $883,045,000 compared to average rate base for 2011 of $876,356,000. The Company's calculation of the return on average rate base for 2012 was 8.10% (2011 - 8.14%) compared to an approved rate of return of 8.14%. The actual rate of return was just below the middle of the range approved by the Board (7.96% to 8.32%). 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 2012 was $395,793,000 (2011 - $392,266,000). The Company's actual return on average common equity for the year ended December 31, 2012 was 8.98% (2011 - 9.00%). In 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 2012 the cost of common equity per the Formula was 8.8% (P.U. 17 (2012)). The actual return on average common equity for 2012 was 8.98% 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) was 0.50% under budget in 2012. The capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $2,621,000 (2.96%). However, for each category of expenditure, the variances ranged from an over-budget of 16.40% to an under-budget of 75.55%. Significant variances are explained in our report.

The Company experienced a 1.56% increase in revenue from rates in 2012 as compared to 2011. The increase can be explained by an increase in demand in Gigawatt hours sold.

Net operating expenses in 2012 increased by $1,773,000 from 2011. The increase is primarily due to an increase in pension and early retirement program costs and the accrual of other post-employment benefits ("OPEBs"). These and other 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 2012 are unreasonable.

Non-regulated expenses, net of tax, decreased in 2012 by ($2,693,300). This variance was largely explained by a change of $2,810,300 (credit) in the Part VI.1 tax adjustment allocated by Fortis Inc. among its subsidiaries.

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 2012 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

Based on our review, the 2012 Other Post Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with P.U. 31 (2010).

Based on our review, the 2012 Optional Seasonal Rate Revenue and Cost Recovery Account operated in accordance with P.U. 8 (2011).

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 2012 the Company met four out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey", "Trouble Call Responded to Within 2 Hours" "All Injury/Illness Frequency Rate" and "Gross Operating Cost/Customer". The Company excluded the impact of Tropical Storm Leslie from its reliability statistics.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2012 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 assess reasonableness and prudence in relation to sales of power and energy and 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 costs,
   - 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 as per P.U. 32 (2007) and P.U. 43(2009).

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to P.U. 19 (2003), P.U. 32 (2007) and P.U 43 (2009).

5. Examine the Company's 2012 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 dated December 31, 2005. Assess reasonableness 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 regulatory deferrals.

10. Conduct an examination of the Pension Expense Variance Deferral Account to assess compliance with P.U. 43 (2009).

11. Conduct an examination of the Other Post-Employment Benefits Expense Variance Deferral Account to assess compliance with P.U. 31 (2010).

12. Conduct an examination of the Optional Seasonal Rate Revenue and Cost Recovery Account to assess compliance with P.U. 8 (2011).

13. Complete a review of the 2012 Board Orders to assess compliance with Board directives.

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

- inquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

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.

The financial statements of the Company for the year ended December 31, 2012 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 6, 2013. 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 April 9, 2012, the Company filed a summary of revisions to its system of accounts with the Board, along with a copy of the revised System of Accounts. In submitting these changes the Company noted that the revisions were mainly due to changes arising from specific Board Orders, as well as adoption of United States Generally Accepted Accounting Principles ("US GAAP"). The revisions consisted of the addition of new accounts, the deletion of older accounts, as well as account description changes.

We understand that there have been no further changes to the system of accounts since this time.

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

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, 2012 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 2012 was $883,045,000 which is an increase of $6,689,000 (0.76%) over the average rate base for 2011 of $876,356,000.

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 2012; 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 2012, 2011 and 2010 (all figures shown are averages):

(000)'s	2012	2011	2010
Net Plant Investment			
Plant Investment	$1,405,709	$ 1,382,786	$ 1,366,106
Accumulated Depreciation	(589,318)	(580,632)	(573,627)
CIAC's	(30,010)	(29,640)	(29,642)
	786,381	772,514	762,837
Additions to Rate Base			
Deferred Charges (a)	99,125	100,354	103,284
Deferred Energy Replacement Costs (b)	-	-	192
Cost Recovery Deferral for Seasonal/TOD Rates (c)	160	114	-
Cost Recovery Deferral for Hearing Costs (d)	127	380	354
Cost Recovery Deferral for Regulatory Amortizations (e)	2,481	821	-
Cost Recovery Deferral – 2012 Cost of Capital (f)	883	-	-
Cost Recovery Deferral – Conservation (g)	341	568	815
Amortization True-up Deferral (h)	-	-	1,931
Customer Finance Programs (i)	1,487	1,587	1,663
Weather Normalization Reserve (j)		-	983
	104,604	103,824	109,222
Deductions from Rate Base			
Weather Normalization Reserve (j)	4,912	3,487	-
Municipal Tax Liability	-	-	682
Unrecognized 2005 Unbilled Revenue	-	-	2,309
2010 Hearing Costs Adjustment (d)	3	3	-
Other Post Employment Benefits (k)	10,908	3,600	-
Customer Security Deposits (l)	773	700	643
Accrued Pension Obligation (m)	3,899	3,663	3,464
Future Income Taxes (n)	1,683	2,240	2,957
Demand Management Incentive Account (o)	905	964	338
Purchased Power Unit Cost Variance Reserve (o)	-	-	224
	23,083	14,657	10,617
Average Rate Base before Allowances	867,902	861,681	861,442
Rate Base Allowances			
Materials and Supplies	5,332	5,012	4,476
Cash Working Capital	9,811	9,663	9,292
	15,143	14,675	13,768
Average Rate Base	$ 883,045	$ 876,356	$ 875,210

(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 $99,125,000 (2011 - $100,354,000) included in the 2012 rate base consists of average deferred pension costs of $98,871,000 (2011 - $100,089,000) and credit facility costs of $255,000 (2011 - $264,000). The Company has included a schedule of these costs in Return 8.

(b) In P.U. 32 (2007) the Board approved the deferral of 2007 replacement energy costs associated with the Rattling Brook Hydro Generating plant refurbishment in the amount of $1,147,000 over a three-year amortization period. These costs were fully amortized at the end of 2010.

(c) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to 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". The calculation of the 2012 average rate base incorporates $160,000 (2011 - $114,000) related to this deferral account.

(d) In P.U. 43 (2009) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2010, hearing costs related to the 2010 GRA in the amount of $750,000. During 2010, the Company deferred $760,000, $10,000 higher than the approved amount, of 2010 GRA hearing costs. In P.U. 26(2011), the Board ordered Newfoundland Power to adjust the recovery of its 2010 hearing costs to reflect total costs of $750,000, as originally approved in the Board Order. Average rate base includes an addition of $124,000 (2011 - $377,000) which represents the unamortized average balance of the original $760,000 offset by a deduction of $3,000. This amount was fully amortized at December 31, 2012

(e) On August 31, 2010 Newfoundland Power submitted an application proposing to defer recovery, until a further Order of the Board, of the amount of $2,363,000 ($1,642,000 after tax) in 2011 to offset the net impact of the expiring amortizations relating to the Municipal Tax Liability, Unrecognized 2005 Unbilled Revenue, Deferred Energy Replacement Costs and the Purchased Power Unit Cost Variance Reserve. This application was approved by the Board in P.U. 30 (2010). P.U. 22 (2011) approved the deferral in 2012 of an additional $2,363,000 ($1,678,000 after tax) related to these expiring amortizations. Included in the calculation of the average rate base for 2012 is $2,481,000 (2011 - $821,000) related to this deferral.

(f) In P.U. 17 (2012) the Board approved the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs. Included in average rate base is $883,000 (2011 - $Nil) related to this deferral.

(g) In P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,0000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan.

(h) The Amortization True-up Deferral was created to extend the impact of the Amortization True-up that arose from the Company's 2002 amortization study filed in the 2003 GRA. In P.U. 32 (2007) the Board approved the Company's proposal to amortize the balance at December 31, 2007 of $11,586,000 over a three year period commencing in 2008. The balance was fully amortized as at December 31, 2010.

(i) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2012 average rate base incorporates $1,487,000 (2011 - $1,587,000) related to these programs.

(j) In P.U. 32 (2007) the Board approved the amortization of the 2006 balance in the Degree Day Component of the Weather Normalization Reserve. Since it was determined that the balance of $6,800,000 was unlikely to reverse, the amount was to be amortized over five years. The calculation of the 2012 average rate base incorporates amortization of $1,364,000 for the non-reversing portion of the reserve. This balance is now fully amortized as of December 31, 2012.

The Weather Normalization reserve was also impacted during 2012 by the following:

i. $1,249,000 transfer to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer
ii. $2,829,000 transfer from the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer

The net impact of these transfers plus the amortization of $1,364,000 resulted in a total transfer from the reserve of $216,000. The ending balance in this reserve account totaled $4,804,000 (i.e. amount owed to customers) compared to a balance of $5,020,000 at December 31, 2011.

(k) Other Post Employment Benefits is equal to the difference, at December 31, 2012, between the OPEBs liability of $60,169,000 and the OPEBs asset of $45,552,000. The calculation of the 2012 average rate base is equal to the average of the December 31, 2012 net liability of $14,617,000 and the December 31, 2011 net liability of $7,199,000.

(l) 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 2012 average rate base incorporates $773,000 (2011 - $700,000) related to customer security deposits.

(m) The 2012 average rate base calculation incorporates $3,899,000 (2011 - $3,663,000) 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.

(n) In 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 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 included future income taxes related to pension costs and OPEBs included in the 2012 average rate base is $283,000 and ($2,984,000) respectively. The remaining balance of the future income tax liability in the amount of $4,384,000 relates to capital assets.

(o) In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland Hydro's proposed demand and energy rate structure. This reserve mechanism was the Purchased Power Unit Cost Variance Reserve used to limit variations in the cost of purchased power associated with the demand and energy structure implemented as of January 1, 2005. In P.U. 32 (2007) the Board approved the amortization of the 2006 balance of $1,342,000 over a three year period beginning in 2008. The balance was fully amortized at the end of 2010. In addition, P.U. 32 (2007) also approved the Company's proposal to discontinue the Purchased Power Unit Cost Variance Reserve Account and establish the Demand Management Incentive Account. In P.U. 8 (2013) the Board approved the disposition of the 2012 balance of the Demand Management Incentive Account of $785,446 (less the related income tax) by means of a credit to the Rate Stabilization Account as of March 31, 2013.

The net change in the Company's average rate base from 2011 to 2012 can be summarized as follows:

(000's)	**2012**	**2011**
Average rate base - opening balance	**$ 876,356**	$ 875,210
Change in average deferred charges and deferred regulatory costs	**881**	(4,340)
Average change in:		
Plant in service	**22,922**	16,635
Accumulated depreciation	**(8,685)**	(6,959)
Contributions in aid of construction	**(370)**	2
Weather normalization reserve	**(1,425)**	(4,470)
Unrecognized 2005 unbilled revenue	**-**	2,309
Other post employment benefits	**(7,308)**	(3,600)
Future income taxes	**556**	717
Other rate base components (net)	**118**	852
Average rate base - ending balance	**$ 883,045**	$ 876,356

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2012 average rate base and conclude that the 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 2012 was 8.10% (2011 - 8.14%). 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 2012, the return on average rate base is calculated in accordance with the methodology approved in P.U. 43 (2009).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2010 to 2012 is set out in the table below.

	2012	2011	2010
Actual Return on Average Rate Base	8.10%	8.14%	8.24%
Upper End of Range set by the Board	8.32%	8.14%	8.41%
Lower End of the Range set by the Board	7.96%	7.78%	8.05%

The Board approved the Company's rate of return on average rate base of 8.14% in a range of 7.96% to 8.32% for 2012 in P.U. 17 (2012). As noted above, the Company's actual return on average rate base for 2012 was 8.10% which was within the range set by the Board. The actual rate of return for 2010 and 2011 were both 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 P.U. 43 (2009) the Board reconfirmed its previous position as per P.U. 32 (2007) 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 2012 as reported in Return 24 is as follows:

	2012 Average		**2011**	**2010**
	(000's)	**Percent**	Percent	Percent
Debt	**$ 484,314**	**54.47%**	54.22%	54.41%
Preferred equity	**9,081**	**1.02%**	1.04%	1.04%
Common equity	**395,793**	**44.51%**	44.74%	44.55%
	$ 889,188	**100.00%**	100.00%	100.00%

Pursuant to 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 2010 year in Return 26. The embedded cost of debt for 2012 was 7.48% which represents a 16 bps decrease from 2010 test year embedded cost of debt of 7.64%.

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 Board Order P.U. 43 (2009).

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, 2012 is included on Return 27 of the annual report to the Board. The average common equity for 2012 was $395,793,000 (2011 - $392,266,000). The Company's actual return on average common equity for 2012 was 8.98% (2011 - 9.00%).

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 P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007) and P.U. 43(2009).
- recalculated the rate of return on common equity for 2012 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 43 (2009).

In 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 2012 the cost of common equity was 8.80% as per P.U. 17 (2012). The actual return on average common equity for 2012 was 8.98% as noted above. This return was within the 50 basis point trigger and as such no report was required. P.U. 17 (2012) also approved the establishment of the 2012 cost of capital cost recovery deferral account to allow for the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of the Company's 2010 test year costs.

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 two years is as follows:

(000's)	**2012**	2011
Net income	**$ 37,204**	$ 32,467
Income taxes	**10,861**	17,661
Interest on long term debt	**35,039**	35,444
Interest during construction	**(820)**	(970)
Other interest and amortization of debt discount costs	**1,258**	1,010
Total	**$ 83,542**	$ 85,612
Interest on long term debt	**$ 35,039**	$ 35,444
Other interest and amortization of debt discount costs	**1,258**	1,010
Total	**$ 36,297**	$ 36,454
Interest Coverage (times)	**2.30**	2.35

The above table shows that the interest coverage decreased in 2012 over 2011 by 0.05 times. The decrease over prior year is primarily due to the Company's lower pre-tax earnings.

In 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 2012 is 2.30 times.

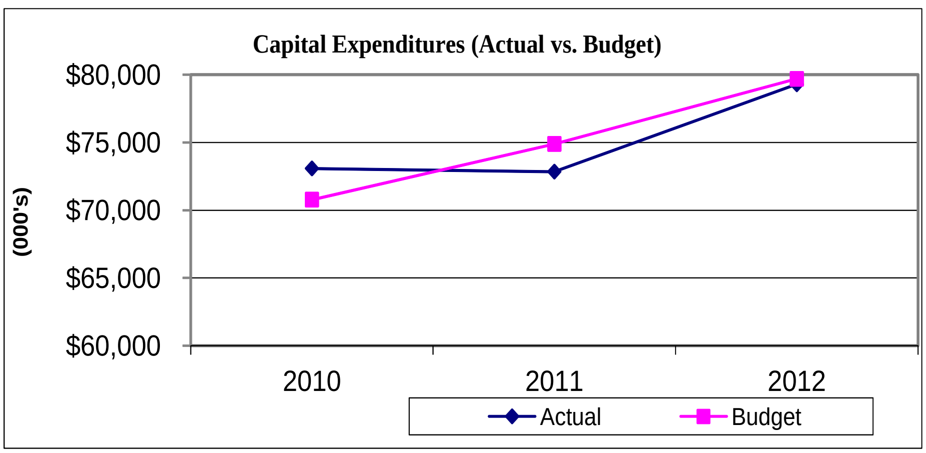
Capital Expenditures

Scope: ***Review the Company's 2012 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 2010 to 2012.

(000's)	2010	2011	2012	
Actual	$ 73,082	$ 72,846	**$ 79,290**	(1)
Budget	$ 70,779	$ 74,894	**$ 79,690**	
Over (under) budget	3.25%	(2.73%)	**(0.50%)**	

(1) Total expenditures per the 2012 Capital Budget report include the carryover amount of $630,000 for a total of $79,920,000. The carryover amount is made up of two projects - $345,000 relating to renovation work and $285,000 relating to feeder additions. According to the Company, these expenditures will occur in 2013.



The following table provides a summary of the capital expenditure activity in 2012 as reported in the Company's *"2012 Capital Expenditure Report"*.

	Capital Budget			Actual Expenditures		
(000's)	**2011**	**2012**	**Total**	**2011**	**2012**	**Total**
2012 Capital Projects and GEC (1) and (5)	$ -	$ 79,690	**$ 79,690**	$ -	$ 79,290	**$ 79,290**
2011 Projects carried to 2012						
Facility Rehabilitation	1,610	-	**1,610**	1,285	189	**1,474**
Horse Chops Rewind and Rotor Re-insulation(2)	1,276	-	**1,276**	795	57	**852**
Rebuild Transmission Lines (3)	4,745	-	**4,745**	3,389	343	**3,732**
Feeder Additions for Growth (4)	1,281	-	**1,281**	470	163	**633**
	8,912	-	**8,912**	5,939	752	**6,691**
	$ 8,912	$ 79,690	**$ 88,602**	$ 5,939	$ 80,042	**$ 85,981**

(1) Approved by Orders P.U. 26 (2011), P.U. 7 (2012), P.U. 8 (2012), P.U. 22 (2012), P.U. 28 (2012) and P.U. 30 (2012)

(2) The total original budget for the Horse Chops Rewind and Rotor Re-insulation project as noted above was $1,276,000. Total expenditures to December 31, 2012 were $852,000 which is $424,000 below the original budget. The Company noted that the favorable variance was the caused by lower contract prices than were anticipated.

(3) The total original budget for the Rebuild Transmission Lines (2011) project as noted above was $4,745,000. Total expenditures to December 31, 2012 were $3,732,000 which is $1,013,000 below the original budget. Most of the variance is due to the fact that approximately $822,000 was deferred included in the 2012 capital budget.

(4) The total original budget for the Feeder Additions for Growth (2011) project as noted above was $1,281,000. Total expenditures to December 31, 2012 were $633,000 which is $648,000 below the original budget. Most of the variance is due to the fact that work is still be completed and will be included in the 2014 Capital Budget Application.

(5) Total expenditures per the 2012 Capital Budget include the carryover amount of $630,000 for a total of $79,920,000. See note 1 on the previous page.

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

(000's)	2012 Budget [1]	2012 Actuals	Variance	%
Generation - Hydro	$ 12,819	$ 9,877 [2]	$ (2,942)	(22.95%)
Generation - Thermal	156	117	(39)	(25.00%)
Substations	12,776	12,741	(35)	(0.27%)
Transmission	10,322	8,426 [2]	(1,896)	(18.37%)
Distribution	39,328	41,487 [2]	2,159	5.49%
General property	2,026	1,702	(324)	(15.99%)
Transportation	2,476	2,514	38	1.53%
Telecommunications	454	111	(343)	(75.55%)
Information systems	3,680	3,982	302	8.21%
Unforeseen	1,065	950	(115)	(10.80%)
General expenses capitalized	3,500	4,074	574	16.40%
Total	$ 88,602	$ 85,981	$ (2,621)	(2.96%)

1 -Includes prior year and current year budgeted amounts as there were projects incomplete at the previous year end. The 2012 budget for Generation - Hydro includes $1,610,000 and $1,276,000 carried forward from the 2011 budget relating to Facility Rehabilitation and Horse Chops Rewind and Rotor Re-insulation respectively. The 2012 budget for Transmission includes $4,745,000 carried forward from the 2011 budget relating to Rebuilding Transmission Lines. The 2012 budget for Distribution includes $1,281,000 carried forward from the 2011 budget relating to Feeder Additions for Growth.

2 - 2012 actuals include the total expense for projects carried forward from 2011. Total costs for Generation - Hydro include the carry forward of Facility Rehabilitation costs of which $1,285,000 was spent in 2011 with a further $189,000 spent in 2012 and the carry forward of Horse Chops Rewind and Rotor Re-insulation costs of which $795,000 was spent in 2011 with a further $57,000 spent in 2012. Total costs for Transmission include the carry forward of Transmission Lines Rebuilding costs of which $3,389,000 was spent in 2011 with at further $343,000 spent in 2012. Total costs for Distribution include the carry forward of Feeder Addition costs of which $470,000 was spent in 2011 with a further $163,000 spent in 2012.

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 $2,621,000 (2.96%). However, for each category of expenditure, the variances ranged from an over-budget of 16.40 % to an under-budget of 75.55%. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. In addition, the Company has noted that there is $630,000 related to projects that will be carried forward to 2013 which include Trunk Feeders ($285,000) and Company Building Renovations ($345,000). The explanations provided by the Company indicate that the capital expenditure variances for 2012 were caused by a number of factors. The Company has provided detailed explanations on budget to actual variances in its “2012 Capital Expenditure Report”. For a complete review of the budget variance we refer to the reader to this report, Appendix A.

The more significant variances noted above were as a result of the following:

Generation - Hydro

- The favorable variance of $2,942,000 is primarily due to an extended implementation period of the *Rattling Brook Dam Replacement* project, resulting in a 2012 variance of $2,256,000, with work to be completed over a 5-year period from 2012 to 2016. Also contributing to the variance is a $387,000 favorable variance on the *Lockston Plant Refurbishment* project and a $424,000 favorable variance on the *Horse Chops Rewind and Rotor Re-insulation* project. These variances were a result of competitive bids from suppliers which led to a lower contract price than was anticipated in the original project estimate. The favorable variance was partially offset by a $254,000 unfavorable variance on the *Facility Rehabilitation* project.

Transmission

- The favorable variance of $1,896,000 is partially due to the reduction of the *2011 Rebuild Transmission Lines* project expenditure by $1,013,000 as $822,000 of the project was deferred and included in the 2012 Capital Budget, and competitive bidding saved approximately $250,000. Also contributing to the variance is the *2012 Rebuild Transmission Lines* project for the rebuilding of transmission line 110L which resulted in lower expenditures as the scope of work was less than anticipated by $591,000.

Distribution

The unfavorable variance in Distribution of $2,159,000 is comprised of the following items:

(000's)	**Budget**	**Actuals**	**Variance**	**%**
Extensions	$ 10,326	$ 11,321	$ 995	9.64%
Meters	1,884	2,557	673	35.72%
Services	3,351	4,508	1,157	34.53%
Street Lighting	2,115	2,364	249	11.77%
Transformers	7,944	6,565	(1,379)	(17.36%)
Reconstruction	2,861	3,463	602	21.04%
Rebuild Distribution Lines	3,403	3,723	320	9.40%
Relocate/Place Distribution Lines for Third Parties	2,205	2,195	(10)	(0.45%)
Trunk Feeders	848	779	(69)	(8.14%)
2012 Feeder Additions for Growth	1,391	1,486	95	6.83%
AFUDC	182	192	10	5.49%
Bell Island Submarine Cable 1	510	588	78	15.29%
MIL-02 Feeder Upgrade	1,027	1,113	86	8.37%
2011 Feeder Additions for Growth	1,281	633	(648)	(50.59%)
Total	$ 39,328	$ 41,487	$ 2,159	5.49%

- The unfavorable variance in "Meters" of $673,000 is primarily due to higher than anticipated customer growth along with higher than budgeted meter replacements.

- The unfavorable variance in "Services" of $1,157,000 is a primarily due a higher than normal number of service replacements that resulted from damage related to Tropical Storm Leslie. The actual number of new connections was also higher than budgeted for 2012.

- The unfavorable variance of $249,000 in "Street Lighting" is a result of higher than anticipated new customer connections as compared to budgeted figures.

- The favorable variance of $1,379,000 in "Transformers" was a result of lower than anticipated contract prices obtained through competitive tendering.

- The unfavorable variance of $602,000 in "Reconstruction" is attributed to a higher than expected amount of work completed under this project. The number of high priority projects that required immediate attention, including work associated with Tropical Storm Leslie, was higher than the historical 5-year average.

- The favorable variance of $648,000 in "2011 Feeder Additions for Growth" is due primarily to work estimated at $450,000 on aerial feeders out of St. John's Main Substation not being completed during 2011 or 2012, due to efforts to reach agreement with affected landowners. This has now been done. This work has been included in the 2013 Capital Budget.

Telecommunications

- The favorable variance of $343,000 is primarily due to the fact that no construction work was performed in relation to the *Fiber Optic Circuit Replacement.* The Company negotiated a long term leasing arrangement for the fiber optic cables and as a result construction was suspended.

Allowance for Unforeseen Items

- The favorable variance of $115,000 is related to the budget for Allowance for Unforeseen Items being increased from the original budget amount by $315,000 as approved in Order No. P.U. 22 (2012) raising the total budget from $750,000 to $1,065,000. The increase in the budget related to repairs to the damaged Bell Island submarine cable with costs of $315,000. The remaining $635,000 was associated with repairs to damage caused to the electrical system that resulted from Tropical Storm Leslie in September 2012.

General expenses capitalized

- The unfavorable variance of $574,000 is related to an increase in the allocated portion of pension expense. Pension expenses increased as a result of the amortization of 2008 losses associated with the pension plan assets, along with a lower discount rate being used to determine the Company's accrued obligation under its defined benefit pension plan. The discount rate used for the year ended December 31, 2012 was 4.4% compared to 5.3% used for the year ended December 31, 2011.

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2012 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 (2.73%) in 2011 and (0.50%) in 2012 resulting in no additional reporting requirements.

Based on our review, the Company's 2012 reporting with respect to allowance for unforeseen items was not in accordance with the Capital Budget Application Guidelines Policy #1900.6 Section B as noted below:

- Under Section B, the Company used the Allowance for Unforeseen Items account to expeditiously deal with events affecting the electrical system which could not wait for Board approval. There were two unforeseen events which required the use of the Allowance for Unforeseen Items account in 2012. The first unforeseen expenditure of $315,000 was required in April 2012 to repair a second fault in an underwater cable supplying Bell Island. A report entitled *Bell Island Submarine Cable Allowance for Unforeseen Items Final Report, July 2012* was submitted to the board on July 13, 2012. Under Section B the final report must be submitted within 30 days of the completion of work on the unforeseen expenditure, which in this case was June 1, 2012. The report relating to the Bell Island Submarine Cable, submitted on July 13, 2012, was submitted over 30 days after the completion of work.

- The second unforeseen expenditure of $635,000 was required in September 2012 to repair damage to the electrical system that resulted from Tropical Storm Leslie. A report entitled *Tropical Storm Leslie Unforeseen Capital Expenditures, September 2012* was submitted to the board on May 2, 2013. Under Section B the final report must be submitted within 30 days of the completion of work on the unforeseen expenditure. The report relating to Tropical Storm Leslie, submitted on May 2, 2013, was submitted over 30 days after the completion of work due to the determination of final costs and vendor invoicing and work pressures resulting from general rate proceedings. This was communicated to the Board in the transmittal letter dated May 2, 2013.

<u>Capital Expenditure Reports</u>

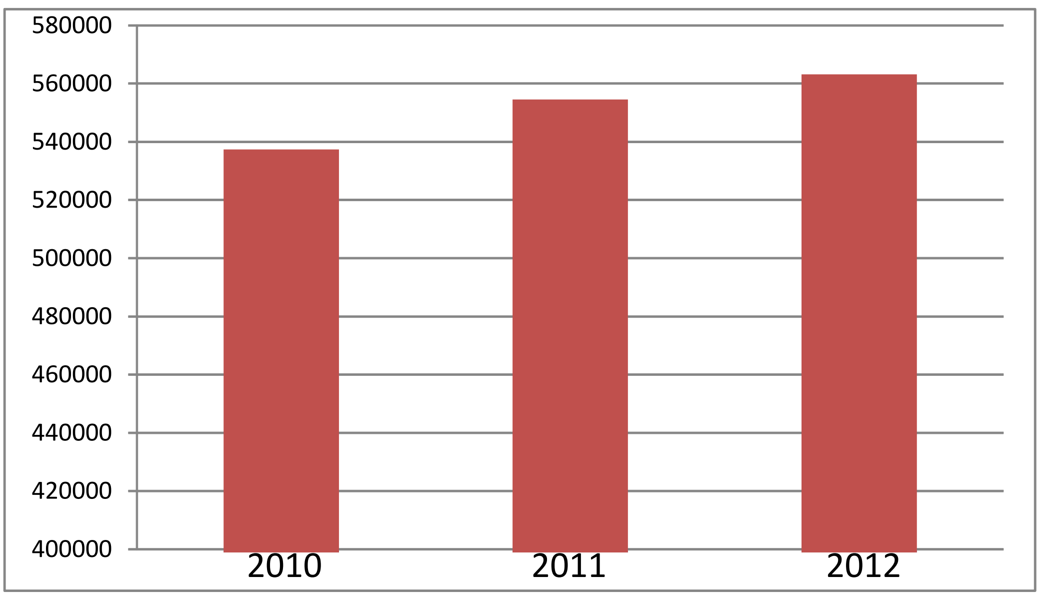
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2012 calendar year.

Revenue

Scope: ***Review the Company's 2012 revenue in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues for 2010 to 2012 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2010	2011	**2012**
Residential	$ 332,664	$ 344,609	**$ 348,325**
General services			
0-10kW	12,331	12,568	**12,890**
10-100kW	65,291	67,341	**67,938**
110-1000kVA	77,976	79,954	**80,641**
Over 1000kVA	31,037	31,500	**34,664**
Street lighting	13,540	13,867	**13,968**
Forfeited discounts	2,494	2,719	**2,737**
Revenue from rates	$ 535,333	$ 552,558	**$ 561,163**
Year over year percentage change	5.82%	3.22%	**1.56%**



The above graph demonstrates that the Company has seen a 1.56% increase in revenue from rates in 2012 as compared to 2011. There was an increase of 10.05% in general services over 1000 kva, as GWh sold increased by 10.66%. There was an increase of 1.08% in revenue from residential sales. GWh sold in this category increased by 1.02%, and the number of residential customers increased by 1.73%.

The comparison by rate class of 2012 actual revenues to 2012 budget is as follows:

(000's)	Actual 2011	Actual 2012	Plan 2012	Actual - Plan Variance	%
Residential	$ 344,609	$ 348,325	$ 351,991	$ (3,666)	-1.04%
General service					
0-10kW	12,568	12,890	12,433	457	3.68%
10-100kW	67,341	67,938	67,204	734	1.09%
110-1000kva	79,954	80,641	80,802	(161)	-0.20%
Over 1000kva	31,500	34,664	32,918	1,746	5.30%
Street lighting	13,867	13,968	14,034	(66)	-0.47%
Forfeited discounts	2,719	2,737	2,956	(219)	-7.41%
Total revenue from rates	$ 552,558	$ 561,163	$ 562,338	$ (1,175)	-0.21%

We have also compared the 2012 energy sales in GWh to those budgeted for 2012.

	Actual 2011	Actual 2012	Plan 2012	Actual - Plan Variance	%
Residential	3,407.0	3,441.5	3,484.5	(43.0)	-1.23%
General service					
0-10kW	93.7	96.4	92.5	3.9	4.22%
10-100kW	665.5	673.6	661.8	11.8	1.78%
110-1000kva	927.7	937.3	939.2	(1.9)	-0.20%
Over 1000kva	422.4	467.4	444.3	23.1	5.20%
Street lighting	36.5	36.0	35.8	0.2	0.56%
Total energy sales	5,552.8	5,652.2	5,658.1	(5.9)	-0.10%

Actual revenue from rates decreased by $1,175,000 (0.21%) from the 2012 Plan, primarily due to a decrease in the average use of electricity by customers. There was a 0.10% decrease in GWh sold in 2012 compared to Plan for 2012. The largest variance can be seen in the residential rate class where actual revenues and energy sales decreased by $3,666,000 (1.04%) and 43.0 GWh (1.23%) respectively, offset by increases in revenues and energy sales in the General Service – 10-100kW and over 1000kva categories.

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.***

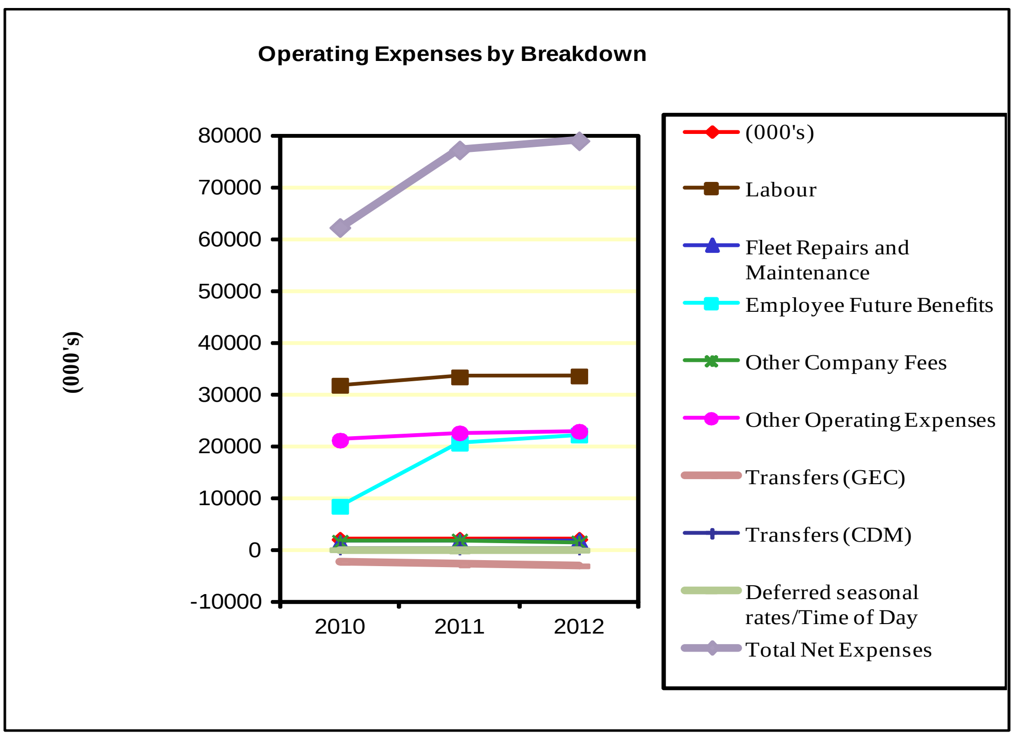
(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012 - 2011
Labour	$ 34,052	$ 33,844	$ 32,531	$ 208
Reclass OPEB labour cost	(503)	(493)	(793)	(10)
Total labour	33,549	33,351	31,738	198
Vehicle expense	1,827	1,779	1,504	48
Operating materials	1,577	1,533	1,271	44
Inter-company charges	1,259	1,277	1,043	(18)
Plants, Subs, System Oper & Bldgs	2,181	1,993	1,814	188
Travel	1,048	1,282	1,124	(234)
Tools and clothing allowance	1,109	1,031	1,139	78
Miscellaneous	1,624	1,468	1,703	156
Conservation	1,341	2,184	654	(843)
Taxes and assessments	988	895	706	93
Uncollectible bills	772	1,204	801	(432)
Insurance	1,188	1,082	1,094	106
Retirement allowance	114	164	712	(50)
Education, training, employee fees	285	318	246	(33)
Trustee and directors' fees	428	399	387	29
Other company fees	1,389	1,748	1,513	(359)
Regulatory costs	1,099	178	179	921
Stationery & copying	304	302	299	2
Equipment rental/maintenance	669	629	773	40
Communications	3,045	3,086	3,009	(41)
Advertising	1,029	906	1,287	123
Vegetation management	1,746	1,612	1,672	134
Computing equipment & software	828	774	799	54
Total other	25,850	25,844	23,729	6
Pension and early retirement program	12,896	11,566	7,588	1,330
OPEB's	9,274	9,003	793	271
Total employee future benefits	22,170	20,569	8,381	1,601
Total gross expenses	$ 81,569	$ 79,764	$ 63,848	$ 1,805
Transfers (GEC)	(3,120)	(2,914)	(2,429)	(206)
Transfers (CDM)	339	339	339	-
Deferred seasonal rates/Time of Day	(84)	(258)	-	174
Deferred regulatory costs	253	253	453	
Total net expenses	$ 78,957	$ 77,184	$ 62,211	$ 1,773

The above table provides details of operating and general expenses by "breakdown" for 2010, 2011 and 2012.

Net operating expenses in 2012 increased by $1,773,000 from 2012. The increase is primarily due to an increase in labour, regulatory, pension and early retirement program costs and OPEBs. These and other 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 2012 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 shows the trend in operating expenses by breakdown for the period 2010 to 2012.

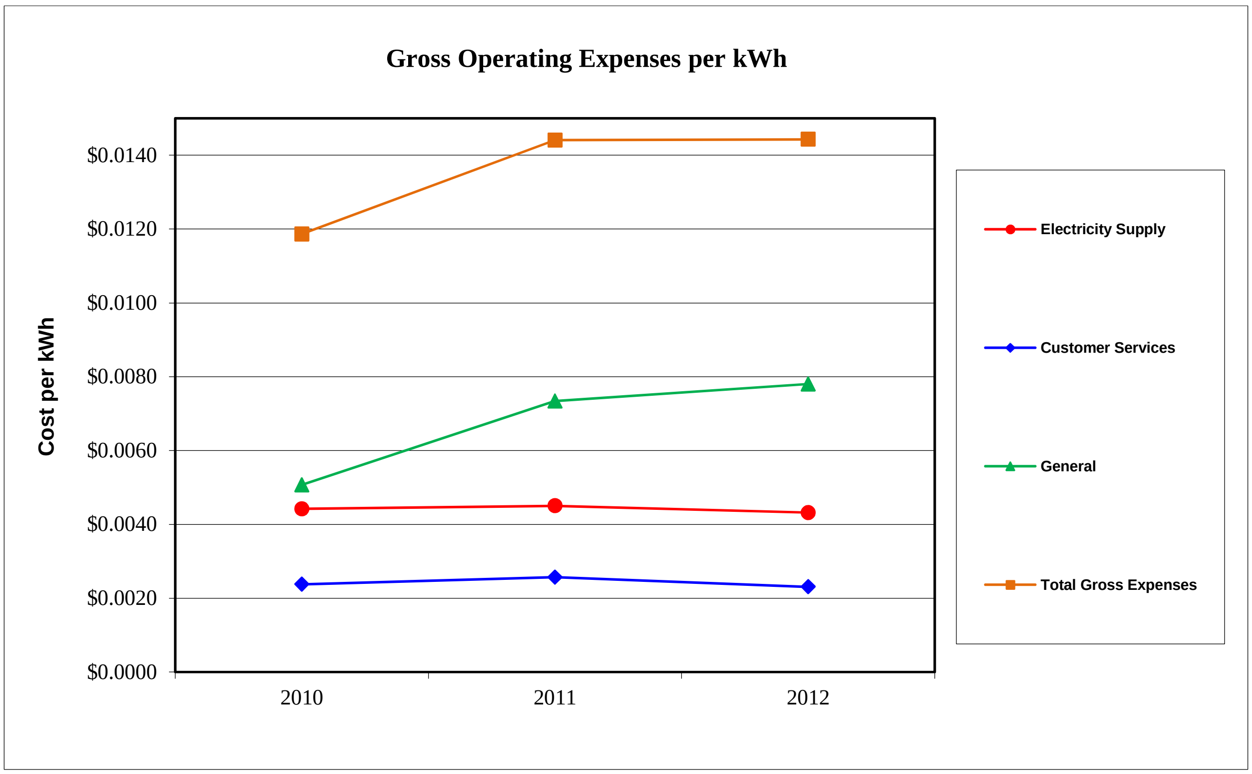
	Actual		
(000's)	**2010**	**2011**	**2012**
Labour	$ 31,738	**$ 33,351**	**$ 33,549**
Fleet Repairs and Maintenance	1,504	**1,779**	**1,827**
Employee Future Benefits	8,381	**20,569**	**22,170**
Other Company Fees	1,513	**1,748**	**1,389**
Other Operating Expenses	21,165	**22,570**	**22,887**
Transfers (GEC)	(2,429)	**(2,914)**	**(3,120)**
Transfers (CDM)	339	**339**	**339**
Deferred seasonal rates/Time of Day	-	**(258)**	**(84)**
Total Net Expenses	$ 62,211	$ 77,184	**$ 78,957**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2010 to 2012 is presented in the table below.

Comparison of Gross Operating Expenses to Total kWh Sold

		Electricity Supply		Customer Services		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
2010	5,419,000	$ 23,946	$0.0044	$ 12,872	$0.0024	$ 27,483	$0.0051	$ 64,301	$0.0119
2011	5,552,800	$ 25,009	$0.0045	$ 14,253	$0.0026	$ 40,755	$0.0073	$ 80,017	$0.0144
2012	5,652,200	$ 24,420	$0.0043	$ 13,052	$0.0023	$ 44,097	$0.0078	$ 81,569	$0.0144



The table and graph show that total gross expenses per kWh have remained consistent from 2011 to 2012.

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 2010 to 2012 is as follows:

	Actual 2012	Plan 2012	Actual 2011	Actual 2010	Actual - Plan 2012	Actual 2012-2011
Executive Group	**6.7**	**6.5**	7.0	7.0	0.2	(0.3)
Corporate Office	**19.2**	**18.2**	17.9	19.0	1.0	1.3
Finance	**72.3**	**73.8**	71.2	68.2	(1.5)	1.1
Engineering and Operations	**439.1**	**425.5**	413.3	408.5	13.6	25.8
Customer Relations	**60.3**	**66.6**	62.9	69.3	(6.3)	(2.6)
	597.6	**590.6**	572.3	572.0	7.0	25.3
Temporary employees	**55.0**	**64.4**	67.8	68.6	(9.4)	(12.8)
Total	**652.6**	**655.0**	640.1	640.6	(2.4)	12.5
Year over year percentage change	**1.95%**	**-**	(0.08%)	0.60%		

The overall number of FTE's in 2012 compared to 2011 increased by 12.5. The budgeted number of FTE's in 2012 was 655.0 versus actual of 652.6. The variances between 2012, 2012 Plan and 2011 are the result of the following:

- The Executive decreased compared to 2011 as a result of two retirements, offset by an employee transferring from Finance.
- The Corporate Office is above 2012 Plan and 2011 as a result of two new hires, offset by a resignation.
- Finance is below 2012 Plan as a result of a retirement and an employee transferred to another department. 2012 is above 2011 as a result of six new hires offset by a retirement, a maternity leave, an employee commencing long-term disability and an employee transferred to another department.
- Engineering and Operations is above 2012 Plan and 2011 as a result of twenty-two new hires, four temporary employees hired permanently and the change in status for Powerline Technician Apprentices from temporary to regular employees, offset by seven resignations and twenty-three retirements.
- Customer Relations is below 2012 Plan and 2011 as a result of one retirement, two employees on long-term disability, delay in hiring two Energy Conservation employees and employees transferred to other departments.
- Temporary Employees are below 2012 Plan and 2011 as a result of status change for Powerline Technician Apprentices (PLT-As). As of May 2012, PLT-As were counted as Regular employees.

An analysis of salaries and wages by type of labour and by function from 2010 to 2012 is as follows:

(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Type				
Internal labour	**$ 57,280**	$ 54,158	$ 52,601	$ 3,122
Overtime	**5,326**	5,758	6,146	(432)
	62,606	59,916	58,747	2,690
Contractors	**11,192**	9,743	10,443	1,449
	$ 73,798	$ 69,659	$ 69,190	$ 4,139
Function				
Operating	**$ 34,052**	$ 33,844	$ 32,531	$ 208
Capital and miscellaneous	**39,746**	35,815	36,659	3,931
Total	**$ 73,798**	$ 69,659	$ 69,190	$ 4,139
Year over year percentage change	5.94%	0.68%	15.10%	

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 2012 were $4,139,000 (5.94%) higher than 2011.

Internal labour costs in 2012 were higher than 2011 by 5.76% primarily due to normal salary increases. Of the $3,122,000 increase, $2,123,000 relates to year-over-year average salary increases and $962,000 is due to an increase in the number of FTEs.

Overtime for 2012 was lower than 2011 by 7.50% due to the use of more contract labour.

Contractors are used to supplement the Company's work force during peak periods of construction. The 14.9% increase in contract labour from 2011 was due primarily to increased customer related work associated with the Company's 2012 capital program. Of this work, the most notable was an increase in infrastructure required to serve new customers.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 2010 to 2012 are included in the table below:

(000's)	Salary Cost Per FTE			
	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Total reported internal labour costs	**$ 57,280**	$ 54,158	$ 52,601	$ 3,122
Benefit costs (net)	**(7,074)**	(6,909)	(7,118)	(165)
Other adjustments	**(525)**	(376) [1]	(554)	(149)
Base salary costs	**49,681**	46,873	44,929	2,808
Less: executive compensation	**(1,806)**	(1,690)	(1,555)	(116)
Base salary costs (excluding executive)	**$ 47,875**	$ 45,183	$ 43,374	$ 2,692
FTE's (including executive members)	**652.6**	640.1	640.6	
FTE's (excluding executive members)	**648.6**	636.1	636.6	
Average salary per FTE	**76,128**	73,228	$ 70,135	
% increase	**3.96%**	4.41%	3.31%	
Average salary per FTE (excluding executive members)	**73,813**	71,031	$ 68,133	
% increase	**3.92%**	4.25%	4.05%	

[1] 2011 adjustments have been restated in 2012. 2011 was previously stated as 261 working days and has been revised in 2012 to 260 working days.

The above analysis indicates that for 2012 the rate of increase in average salary per FTE has been fairly consistent from 2010 to 2012. The Company has noted that the 3.92% increase in average salary per FTE (excluding executive members) is primarily due to annual salary increases and the normal salary progression of new employees in the Company.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2010 to 2012 and the targets set for 2012:

Measure	Target 2012	Actual 2012	Actual 2011	Actual 2010
Controllable Operating Costs/Customer	**$222.1**	$222.2	$214.2	$215.8
Earnings	**33.3m**	34.2m	33.7m	35.0m
Reliability - Duration of Outages (SAIDI)	**2.58**	2.44	2.57	2.59
Customer Satisfaction - % Satisfied	**88.5%**	86.7%	88.5%	89.3%
Customer Satisfaction - 1st Call Resolution	**88.5%**	88.7%	88.5%	88.3%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	**1.72**	1.74	1.8	1.9

The 2012 STI results were adjusted to remove the impact of Tropical Storm Leslie. The 2011 STI results were adjusted to remove the impact of the wind storm in December, new regulations associated with PCB bushing replacement and special insulation program. The 2010 STI results for the calculation of controllable costs per customers, SAIDI and First Call Resolution were adjusted to remove the impact of the March sleet storm and Hurricane Igor. The Company's STI program also includes an individual performance measure for Executives and Managers. 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%
Other Executives	50%	50%
Managers	50%	50%

The individual measures of performance for Managers 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 2012 is established as a percentage of base pay for the three employee groups. For 2012, measures relating to 'earnings', 'SAIDI' and 'customer satisfaction – 1st call resolution', metrics were met, however the 'controllable operating costs/customer', 'customer satisfaction - % satisfied' and 'safety' metrics fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2010 to 2012:

STI Payout

	Target 2012	Actual 2012	Target 2011	Actual 2011	Target 2010	Actual 2010
President	**50%**	**70.0%**	**50%**	**63.6%**	40%	54.1%
Executive	**35-40%**	**51.1%**	**35-40%**	**48.2%**	30%	40.3%
Managers	**15%**	**20.2%**	**15%**	**16.9%**	15%	18.1%

STI actual payout rates for all three employee groups are higher than in the prior year.

In dollar terms, the STI payouts for 2010 to 2012 are as follows:

	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
President	**$ 280,000**	$ 245,000	$ 200,000	$ 35,000
Executive	**381,000**	345,000	280,000	36,000
Managers	**271,000**	245,200	226,800	25,800
Total	**$ 932,000**	$ 835,200	$ 706,800	$ 96,800
Year over year percentage change	**11.59%**	18.17%	-2.71%	

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In 2012, the non-regulated portion (before tax adjustment) was $170,200 (2011 - $26,400).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2010 to 2012.

	Base Salary	Short Term Incentive	Other	Total
2012				
Total executive group	$ 1,145,021	$ 661,000	$ 129,201	$ 1,935,222
Average per executive (4)	**$ 286,255**	**$ 165,250**	**$ 32,300**	**$ 483,805**
2011				
Total executive group	$ 1,100,319	$ 590,000	$ 127,325	$ 1,817,644
Average per executive (4)	**$ 275,080**	**$ 147,500**	**$ 31,831**	**$ 454,411**
2010				
Total executive group	$ 1,064,994	$ 480,000	$ 169,207	$ 1,714,201
Average per executive (4)	**$ 266,249**	**$ 120,000**	**$ 42,302**	**$ 428,550**
% Average increase 2012 vs 2011	**4.06%**	**12.03%**	**1.47%**	**6.47%**

Note: The 2010 results for executive compensation were adjusted to remove the impact of amounts paid to Vice President, Customer and Corporate Services. This position was vacated effective January 12, 2010.

Base salary for the executive group increased from 2011 due to salary increases approved by the Board of Directors. Base salaries have been agreed to the 2012 Board of Directors' minutes, and STI payouts have been agreed to the 2013 Board of Directors' minutes.

Company Pension Plan

For 2012, we reviewed the accounts supporting the gross charge of $12,895,934 for the pension expense accounts of the Company. A detailed comparison of the components of pension expense for 2010 to 2012 is as follows:

	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Pension expense per actuary	**$ 11,153,000**	$ 10,056,965	$ 6,173,359	$ 1,096,035
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**484,934**	444,163	457,459	40,771
Group RRSP @ 1.5%	**459,000**	467,000	475,758	(8,000)
Individual RRSP's	**813,000**	616,000	533,262	197,000
Less: Refunds (net of other expenses)	**(14,000)**	(18,128)	(51,484)	4,128
Total	**$ 12,895,934**	$ 11,566,000	$ 7,588,354	$ 1,329,934
Year over year percentage change	11.50%	52.42%	183.86%	

Overall, pension expense for 2012 is higher than 2011 primarily due to a lower discount rate at December 31, 2011, which is used to determine the pension obligation for 2012, as well as a lower service life of active members.

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 P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses increased by 9.18% in 2012.

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. The increase of approximately $189,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2011 was primarily the result of new hires and wage increases. This was partially offset by retirements and terminations.

Retirement Allowance

The retirement allowance costs incurred by the Company over the period from 2010 to 2012 are as follows:

(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Terminations and Severance	$ **100** [3]	$ 154	$ 501	$ (54)
Normal Retirements [1]	-	-	240	-
Other Retiring Allowance Costs	**14**	10	(29)	4
Total	$ **114**	$ 164	$ 712	$ (50)
Year over year percentage change [2]	-30.49%	-76.97%	493.33%	

[1] There were 27 retirements in 2012 compared to 22 reitrements in 2011.
[2] In 2011, retirement allowances were included as a part of OPEBs expense upon adoption of the accrual accounting for OPEBs as specified in P.U. 31 (2010).
[3] This represents an accrual which was recorded at the end of 2012 for pending severances/terminations.

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 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 the 2012 OPEBs expense are as follows:

(000s)	2012	2011
Accrued OPEBs	$ 6,212	$ 5,895
Amortization of transitional balance	3,504	3,504
Amount capitalized	(397)	(373)
Future income taxes	(45)	(23)
	$ 9,274	$ 9,003

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) and P.U. 43 (2009);
- compared intercompany charges for the years 2010 to 2012 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2012 and investigated any unusual items;
- vouched a sample of transactions for 2012 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 2010 to 2012 for charges to and from Newfoundland Power Inc.:

	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Charges from related companies				
Regulated	**$ 202,524**	$ 130,719	$ 318,344	$ 71,805
Non-Regulated	**1,575,092**	1,602,265	1,404,293	(27,173)
Total	**$ 1,777,616**	$ 1,732,984	$ 1,722,637	$ 44,632
Charges to related companies	**$ 659,162**	$ 913,593	$ 956,364	$ (254,431)

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 2012.

- Fortis Inc. estimated its net pool of operating expenses for 2012 in Q4 2011 as part of its annual business planning process 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 evenly based upon 25% of the estimated annual amount.
- Similar to 2011, certain staffing and staffing related charges, as well as certain consulting and legal fees, were included in the pool of recoverable expenses. Of these expenses, Fortis deemed 50% of the CEO's, CFO's and Treasurer's salary and related costs to be borne by Fortis Inc. for business development and consequently these costs are excluded from the pool of recoverable expenses. Additionally, certain consulting and legal fees that are attributable to business acquisition activity are excluded. This is consistent with 2011.
- Fortis Inc. used actual year-to-date expenditures up to October and estimated November and December's expenses for the determination of its actual "true up" calculation. Fortis also used actual assets at October 30, 2012 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of November and December's expenditures had a minimal impact.

During the fourth quarter of 2012, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $1,259,000 and are summarized as follows:

2012 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$557,000	Non-regulated
Director Fees	196,000	Non-regulated
Consulting and Legal fees	148,000	Non-regulated
Trustee Agent Fees	52,000	Regulated
Audit and Other Fees	33,000	Non-regulated
Public Reporting Costs	63,000	Non-regulated
Annual Meeting Expenses	47,000	Non-regulated
Travel (Board and Other)	23,000	Non-regulated
Insurance (D&O)	43,000	Non-regulated
Other Costs	97,000	Non-regulated
	1,259,000	
Less amounts previously billed:		
Q1 2012	310,000	
Q2 2012	310,000	
Q3 2012	310,000	
Q4 2012 balance owing	$ 329,000	

For 2012, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 9.72%, down from 10.43% in 2011.

As detailed above, trustee agent fees for $52,000 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 2010 to 2012 with Fortis Inc.:

Intercompany Transactions

(Regulated)	**Actual 2012**	**Actual 2011**	**Actual 2010**	**Variance 2012-2011**
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 52,000**	$ 51,000	$ 45,000	$ 1,000
Miscellaneous	**13,362**	7,629	12,483	5,733
Non-Joint Use Poles	**-**	11,566	13,512	(11,566)
	$ 65,362	$ 70,195	$ 70,995	$ (4,833)
Year over year percentage change	**-6.89%**	-1.13%	-11.68%	
Charges to Fortis Inc.				
Postage and couriers	**$ 24,457**	$ 22,263	$ 20,851	$ 2,194
Staff charges	**201,332**	299,786	500,948	(98,454)
Staff charges - insurance	**203,524**	179,005	213,164	24,519
Pole removal and installation	**3,606**	20,191	23,976	(16,585)
Miscellaneous	**13,367**	92,974	8,747	(79,607)
	$ 446,286	$ 614,219	$ 767,686	$ (167,933)
Year over year percentage change	**-27.34%**	-19.99%	37.56%	

The most significant fluctuation from our analysis of regulated intercompany charges is a $98,454 decrease in staff charges charged to Fortis Inc. As a result of the sale of the vast majority of Fortis-owned non-joint use poles to Bell Aliant in 2010-2011, there was a significant reduction in the amount of pole maintenance work that the Company completed on those poles in 2012. However, this reduction was partially offset by charges related to the Company's involvement in Fortis Inc.'s acquisition project in New York. The charge-out rate used for labour costs related to the project consists of the base hourly rate for each specific employee plus a 71% overhead charge. The employees involved were the President and CEO, Vice-President Customer Operations & Engineering, Vice-President Regulation & Planning, Manager Customer Relations & Information Services, Director, Operations & Support, Director, Procurement and Director, Risk Management. The total charges amounted to $197,585.

Other significant fluctuations included miscellaneous charges to Fortis Inc. ($79,607) and non-joint use pole charges from Fortis Inc. ($11,566). In both cases, the higher amounts in 2011 were a result of the sale of non-joint use poles to Bell Aliant. The $24,519 increase in staff insurance charges charged to Fortis Inc. was due to an increase in labour charges and travel by the Director of Risk Management in carrying out routine insurance and risk related work for Fortis Inc.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2010 to 2012:

(Non-Regulated)	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Charges from Fortis Inc.				
Director's fees and travel	**$ 219,000**	$ 200,000	$ 263,000	$ 19,000
Annual and quarterly reports	**96,000**	117,000	89,000	(21,000)
Staff charges	**557,000**	574,000	352,000	(17,000)
Miscellaneous	**697,130**	711,265	697,877	(14,135)
	$ 1,569,130	$ 1,602,265	$ 1,401,877	$ (33,135)
Year over year percentage change	**(2.07%)**	14.29%	29.38%	

The total non-regulated charges from Fortis Inc. have decreased by 2.07% ($33,135) and are relatively unchanged from 2011.

The following table provides a summary and comparison of the other intercompany transactions for 2010 to 2012:

Intercompany Transactions (Other)	**Actual 2012**	**Actual 2011**	**Actual 2010**	**Variance 2012-2011**
Charges to Fortis Properties				
Staff charges	**$ 864**	**$ -**	$ 1,247	$ 864
Staff charges - insurance	**33,089**	37,042	23,303	(3,953)
Stationary costs	**529**	678	401	(149)
Miscellaneous	**3,134**	2,147	9,745	987
	$ 37,616	$ 39,867	$ 34,696	$ (2,251)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 58,212**	$ 37,387	$ 69,612	$ 20,825
Miscellaneous	**8,944**	8,029	11,814	915
	$ 67,156	$ 45,416	$ 81,426	$ 21,740
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 3,697**	$ 1,622	$ 4,417	$ 2,075
Staff charges	**10,658**	7,065	-	3,593
IS charges	**6,224**	3,351	4,788	2,873
Miscellaneous	**350**	360	360	(10)
	$ 20,929	$ 12,398	$ 9,565	$ 8,531
Charges to Maritime Electric				
Staff charges	**$ 6,418**	$ 16,296	$ 2,312	$ (9,878)
Staff charges - insurance	**10,005**	2,693	1,346	7,312
IS charges	**1,915**	4,787	3,351	(2,872)
Miscellaneous	**540**	550	580	(10)
	$ 18,878	$ 24,326	$ 7,589	$ (5,448)
Charges from Maritime Electric				
Staff charges	**$ 33,932**	$ -	$ 86,218	$ 33,932
Miscellaneous	**5,999**	9,211	7,338	$ (3,212)
	$ 39,931	$ 9,211	$ 93,556	$ 30,720
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	**$ -**	$ 432	$ 1,134	$ (432)
Staff charges	**-**	-	37,456	-
	$ -	$ 432	$ 38,590	$ (432)
Charges to Fortis US Energy Corp				
Staff charges - insurance	**$ 1,176**	$ 2,581	$ -	$ (1,405)

Intercompany Transactions (Other) Cont'd.	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Charges to Belize Electricity				
Staff charges	**$ -**	$ -	$ 3,739	$ -
Staff charges - insurance	**-**	1,296	8,043	(1,296)
Miscellaneous	**-**	1,176	5,177	(1,176)
	$ -	$ 2,472	$ 16,959	$ (2,472)
Charges to FortisAlberta Inc.				
Staff charges	**$ -**	$ 18,219	$ -	$ (18,219)
Staff charges - insurance	**341**	3,365	540	(3,024)
Miscellaneous	**3,270**	3,120	2,990	150
	$ 3,611	$ 24,704	$ 3,530	$ (21,093)
Charges from FortisAlberta Inc.				
Staff charges	**$ -**	$ 4,805	$ 64,914	$ (4,805)
Miscellaneous	**30,637**	-	-	30,637
	$ 30,637	$ 4,805	$ 64,914	$ 25,832
Charges to FortisBC Inc.				
Staff charges	**$ 16,023**	$ -	$ -	$ 16,023
IS charges	**13,405**	13,405	13,405	-
Staff charges - insurance	**715**	5,869	1,410	(5,154)
Miscellaneous	**2,330**	1,944	1,919	386
	$ 32,473	$ 21,218	$ 16,734	$ 11,255
Charges from FortisBC Inc.				
Miscellaneous	**$ -**	$ 1,092	$ 9,859	$ (1,092)
Charges to Fortis BC Holdings				
Staff charges	**$ -**	$ 10,215	$ -	$ (10,215)
Staff charges - insurance	**324**	2,983	540	(2,659)
Miscellaneous	**6,500**	6,547	6,212	(47)
	$ 6,824	$ 19,745	$ 6,752	$ (12,921)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 67,524**	$ 6,938	$ -	$ 60,586
Staff charges - insurance	**162**	21,168	7,452	(21,006)
Miscellaneous	**281**	-	-	281
	$ 67,967	$ 28,106	$ 7,452	$ 39,861
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ 5,400**	$ -	$ -	$ 5,400

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Intercompany Transactions (Other) Cont'd.	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Charges to Fortis Turks and Caicos				
Staff charges	$ **6,638**	$ 117,504	$ 37,679	$ (110,866)
Staff charges - insurance	**16,764**	5,946	8,255	10,818
Miscellaneous	-	75	877	(75)
	$ **23,402**	$ 123,525	$ 46,811	$ (100,123)

The most significant fluctuations from our analysis of other intercompany charges for 2012 compared to 2011 are as follows:

- Hotel/Banquet facilities & meals charges from Fortis Properties increased by $20,825 compared to 2011 as a result of out-of-town staff staying at the Holiday Inn in the aftermath of Tropical Storm Leslie.
- Staff charges from Maritime Electric increased by $33,932 from 2011 as a result of Maritime Electric staff working on restoration of power in the aftermath of Tropical Storm Leslie.
- Staff charges charged to FortisAlberta Inc. decreased by $18,219. The 2011 charges were related to a Newfoundland Power staff member working on a short-term project involving performance based regulation.
- Miscellaneous charges from FortisAlberta Inc. increased by $30,637. These charges consist primarily of Newfoundland Power's share of the CEA Finance & Tax Committee membership fees paid by FortisAlberta ($5,000) and Newfoundland Power's share of pension related expenses for former CEO Philip Hughes ($25,074). The pension charges relate to benefits payments associated with his Supplemental Employee Retirement Plan (SERP). Mr. Hughes retired in 2007 and elected, under the provisions of the plan text, to defer benefits payments for 5 years until May 1, 2012. The charge started in May, 2012 for amounts previously accrued.
- Staff charges to FortisBC Inc. increased by $16,023 from 2011. These charges relate to engineering services provided for a proposed hydroelectric generating project being considered by a subsidiary of FortisBC Inc.
- Staff charges to FortisBC Holdings decreased by $10,215 in 2012. The 2011 charges related to a Newfoundland Power staff member supporting the implementation of new customer service, billing processes and policies for FortisBC Holdings.
- Staff charges to Caribbean Utilities Co. Limited ("CUC") increased by $60,586 from 2011. The increased charges relate to Newfoundland Power staff providing training & facilitating knowledge transfer relating to Newfoundland Power's safety management system and staff engineer development processes. In addition to this, Newfoundland Power's CEO made two trips to CUC in 2012 in his role as member of the Board compared to one such trip in 2011.
- Staff insurance charges to CUC decreased by $21,006 in 2012. Risk management staff made two trips to CUC in 2011 compared to no trips in 2012.
- Staff charges to Fortis Turks and Caicos decreased by $110,866 in 2012 from 2011. The 2011 charges were a result of a Newfoundland Power engineer participating in the design, project supervision & other activities related to a transmission rebuild project.
- Staff insurance charges to Fortis Turks and Caicos increased by $10,818 in 2012 due to risk management staff making two trips compared to one such trip in 2011.

In Order 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 2012. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2012.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2010 General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2012 and noted some exceptions. In cases of staff charges related to routine insurance matters (e.g.; coverage queries, damage claims, arranging for insurance certificates) are based on the recovery of fully distributed costs (hourly rate plus 71% markup). The company indicated that this is in accordance with Section 6.5 – Shared Corporate Services of the Newfoundland Power Inc. Inter-Affiliate Code of Conduct (May 2011) submitted to the Board on June 10, 2011.

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 2012 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Other company fees				
Other company fees	$ 1,389	$ 1,748	$ 1,513	$ (359)
Regulatory hearing costs - other	1,099	178	179	921
	$ 2,488	$ 1,926	$ 1,692	$ 562
Year over year percentage change	29.2%	13.8%	-13.2%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 253	$ 253	$ 453	$ -
Year over year percentage change	0.0%	-44.2%	125.4%	

Other company fees decreased in 2012 as 2011 included higher legal fees and consultant costs required for U.S. GAAP implementation and human resources activity such as arbitration and compensation reviews. "Regulatory hearing costs – other" increased by approximately $921,000 in 2012 due primarily to cost of capital consultants, depreciation experts and legal fees related to Newfoundland Power's 2013/2014 General Rate Application. 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 2010 to 2012 is as follows:

(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Miscellaneous	**$ 857**	$ 858	$ 1,046	$ (1)
Cafeteria and lunchroom supplies	**93**	97	92	(4)
Promotional items	**101**	118	135	(17)
Computer software	**34**	3	1	31
Damage claims	**215**	141	143	74
Community relations activities	**3**	3	14	-
Donations and charitable advertising	**221**	180	194	41
Books, magazines and subscriptions	**67**	45	58	22
Misc. lease payments	**33**	23	20	10
Total miscellaneous expenses	**$ 1,624**	$ 1,468	$ 1,703	$ 156
Year over year percentage change	**10.63%**	(13.80%)	10.94%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2011 to 2012 these expenses have increased by 10.63% overall, primarily because of increased cost for damage claims, customer satisfaction surveys and seasonal rates/time of day.

Donations and charitable advertising included in miscellaneous expenses are non-regulated expenses.

Our procedures in this expense category for 2012 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 2012 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2012 Conservation and Demand Management Report with the Board. This report provided a summary of 2012 CDM activities and costs as well as the outlook for 2013. Costs have decreased over the prior year mainly due to a special insulation event held in 2011 as part of the Energy Savers Programs that significantly increased participation in that year. Costs in 2012 totaled $3,397,000 compared to $4,209,000 in 2011.

Going forward, the Company plans to expand its customer energy conservation program, modifying existing programs and increasing customer education and support activities.

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 2012 and 2011 as follows:

(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Vehicle expense	**1,827**	1,779	1,504	48
Operating materials	**1,577**	1,533	1,271	44
Plants, Subs, System Oper & Bldgs	**2,181**	1,993	1,814	188
Travel	**1,048**	1,282	1,124	(234)
Tools and clothing allowance	**1,109**	1,031	1,139	78
Conservation	**1,341**	2,184	654	(843)
Taxes and assessments	**988**	895	706	93
Uncollectible bills	**772**	1,204	801	(432)
Insurance	**1,188**	1,082	1,094	106
Education, training, employee fees	**285**	318	246	(33)
Trustee and directors' fees	**428**	399	387	29
Stationery & copying	**304**	302	299	2
Equipment rental/maintenance	**669**	629	773	40
Communications	**3,045**	3,086	3,009	(41)
Advertising	**1,029**	906	1,287	123
Vegetation management	**1,746**	1,612	1,672	134
Computing equipment & software	**828**	774	799	54
Transfers (GEC)	**(3,120)**	(2,914)	(2,429)	(206)
Transfers (CDM)	**339**	339	339	-
Deferred seasonal rates/Time of Day	**(84)**	(258)	**-**	174

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

- System operations costs increased by $188,000 due to increased building repairs and property maintenance costs.
- Travel costs decreased by $234,000 due to lower employee relocation costs.
- Conservation costs decreased by $843,000. The higher costs in 2011 were due to significant customer participation in an insulation rebate program.
- Uncollectible bills decreased by $432,000 due primarily to the reversal of a 2011 provision for potentially uncollectible amounts related to the Bell Aliant joint-use pole sale. In addition, uncollectible bills vary from year to year as a result of general economic conditions.
- Insurance costs increased by $106,000 due to increased insurance premiums reflecting market changes and growth in the Company's asset base.
- Advertising costs increased by $123,000. 2011 costs were lower due to increased participation in conservation which reduced the need for addition advertising.
- Vegetation management costs increased by $134,000 due to increased need for vegetation management activity following Tropical Storm Leslie.
- GEC transfers increased by $206,000 due to an increase in pension costs during the year
- In 2011, the Board approved the deferred recovery of costs and revenues associated with implementing the Optional Seasonal/Time of Day Rate Study. Costs were higher in 2011 due to the implementation cost for the Time of Day rate study.

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.***

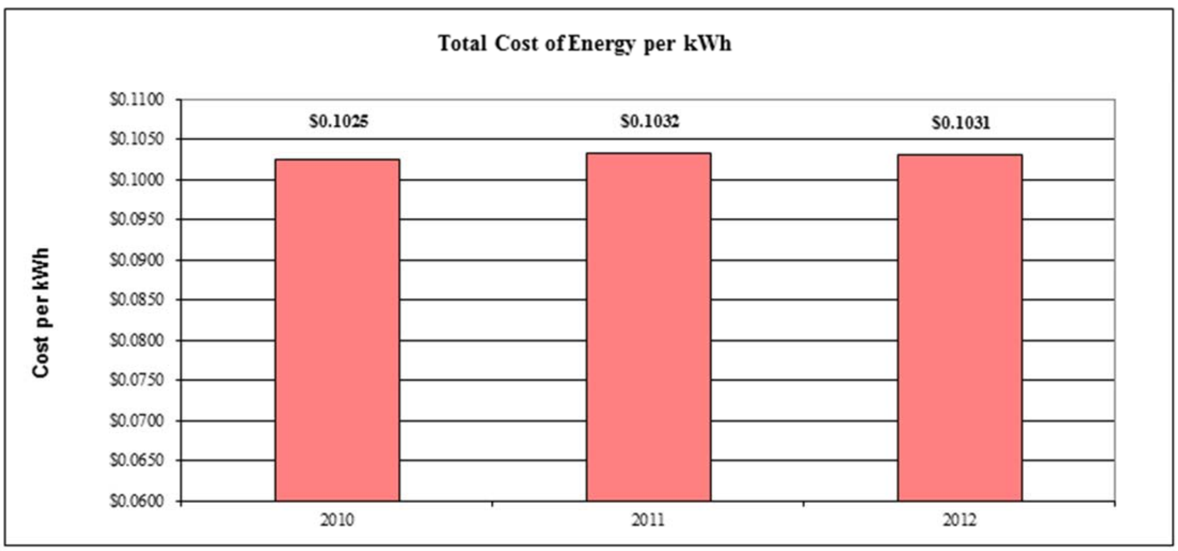
The following table and graph provide the total cost of energy (expressed in kWh) from 2010 to 2012:

(000's)

Year	kWh sold	Operating Expenses	Purchased Power	Cost recovery & Cost of Capital Cost recovery Deferrals	Depreciation	Finance Charges*	Income Taxes	Net Earnings	Total Cost of Energy	Cost per kWh
2010	5,419,000	$ 62,211	$ 358,443	$ -	$ 47,220	$ 36,038	$ 15,870	$ 35,573	$ 555,355	$ 0.1025
2011	5,552,800	$ 77,184	$ 369,484	$ (2,363)	$ 42,695	$ 35,944	$ 17,661 [1]	$ 32,467 [1]	$ 573,073	$ 0.1032
2012	5,652,200	$ 78,957	$ 380,374	$ (4,850)	$ 44,518	$ 35,856	$ 10,861	$ 37,204	$ 582,920	$ 0.1031

* - 2010 Comparative has been restated to reflect 2010 interest charged to construction instead of AFUDC, which included an equity portion.

[1] - Restated as a result of the Company's adoption of U.S. GAAP



Purchased Power

We have reviewed the Company's purchased power expense for 2012 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.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the Gannett Fleming Depreciation Study, dated December 31, 2005 and assessed the reasonableness of depreciation expense.

The changes in depreciation rates and policies flowing from the Gannett Fleming Depreciation Study, dated December 31, 2005, were approved by the Board to be effective January 1, 2008 according to P.U. 32 (2007).

The objective of our procedures in this section was to ensure that the 2012 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the Depreciation Study undertaken by Gannett Fleming, Inc. dated December 31, 2005.

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 2012; and,
- assessed the overall reasonableness of the depreciation for 2012.

Amortization expense for 2012 is $44,518,000 as compared to $42,695,000 for 2011, representing a 4.27% increase. The change is attributable to an increase of depreciable assets by approximately $67,771,000.

Gannett Fleming has recommended that the Company continue to use the straight-line equal life group method that it has been using for a number of years for its plant assets with the exception of certain General and Communication accounts. Amortization accounting is considered appropriate for the General and Communication accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. The study for plant in service as of December 31, 2010 was completed in 2011. The study was included in the 2013-2014 General Rate Application by the Company and was approved in P.U. 13 (2013). The next study for plant in service is to be completed as of December 31, 2014 and included in the 2015-2016 General Rate Application.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006) and P.U. 32 (2007), and the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005 have been incorporated into the Company's depreciation calculations for 2012.

Interest and 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:

(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012-2011
Interest				
Long-term debt	**$ 35,039**	$ 35,444	$ 35,850	$ (405)
Other	**921**	702	334	219
Amortization				
Debt discount	**337**	308	232	29
Capital stock issue	**-**	-	37	-
Interest charged to construction (Note)	**(441)**	(510)	(415)	69
Total finance charges	**$ 35,856**	$ 35,944	$ 36,038	$ (88)
Year over year percentage change	**-0.24%**	-0.26%	4.29%	

Note: 2010 interest charged to construction has been restated to show only the interest portion of AFUDC.

In the above table, the decrease in interest on long term debt compared to 2011 is attributable to the decreasing amount of bonds outstanding.

The increase in other interest reflects changing interest rates on the Company's credit and demand facilities during 2012 compared to 2011.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2012 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2012 and have noted that the effective income tax rate decreased from 35.2% in 2011 to 22.6% in 2012. This decrease is primarily due to timing of pension funding, the tax reserve for unpaid compensation, and the allocation of the Part VI.1 tax liability and related Part 1 tax deduction from Fortis to the Company in 2012. There was also a reduction in the statutory tax rate of 1.5%, from 30.5% in 2011 to 29.0% in 2012.

Comparative figures for 2011 were restated as a result of the Company's adoption of U.S. GAAP in 2012.

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 2012 is unreasonable.

Costs Associated with Curtailable Rates

In 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 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 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 of the curtailment credits for 2012 was $332,754 compared to the 2011 credits of $302,750. Total operating costs incurred by the Company in 2012 were $357,152 compared to $326,253. The increase in credits compared to the previous year is primarily a result of the addition of two participants to the program.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and 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 2012 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2012 and investigated any unusual items;
* 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:

	2012	2011	2010	2012-2011
Charged from Fortis Companies:				
Annual report	**$ 96,000**	$ 117,000	$ 89,000	$ (21,000)
Directors' fees and travel	**219,000**	200,000	263,000	19,000
Hotel/Banquet Facilities	**5,700**	-	-	5,700
Staff charges	**557,000**	574,000	354,400	(17,000)
Miscellaneous	**697,400**	711,300	697,900	(13,900)
	1,575,100	1,602,300	1,404,300	(27,200)
Donations and charitable advertising	**286,800**	266,300	305,500	20,500
Executive short term incentive	**170,200**	26,400	104,500	143,800
Miscellaneous	**79,700**	94,100	109,400	(14,400)
	2,111,800	1,989,100	1,923,700	122,700
Less: Income taxes	**612,400**	606,700	615,500	5,700
Less: Part VI.1 tax adjustment	**2,589,000**	(221,300)	328,900	2,810,300
Total non-regulated (net of tax)	**$ (1,089,600)**	$ 1,603,700	$ 979,300	$ (2,693,300)

In the table above the most significant fluctuation between 2012 and 2011 pertains to the Part VI.1 tax adjustment. This tax adjustment results from the payment by Fortis of dividends on its preferred shares. The Company has noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.'s corporate tax planning and preferred share dividend payment, and the Company's capacity to cover this tax.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2012 this represents an addition to non-regulated expenses (before tax adjustment) of $170,200 (2011 - $26,400). 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 29.0% which agrees with the Company's statutory rate as identified in the 2012 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 2011 and 2012:

(000's)	2012 Actual	2011 Actual	Variance 2012-2011
Regulatory Assets			
Rate stabilization account	**$ 19,529**	$ 12,434	$ 7,095
OPEBs asset	**45,552**	49,056	(3,504)
Weather normalization account	**-**	2,102	(2,102)
Pension deferral	**2,537**	3,665	(1,128)
Cost recovery deferral	**4,726**	2,363	2,363
Cost of capital cost recovery deferral	**2,487**	-	2,487
Deferred GRA costs	**-**	253	(253)
Conservation and demand management deferral	**339**	678	(339)
Optional seasonal rate revenue and cost recovery account	**130**	328	(198)
Employee future benefits (1)	**175,056**	131,250	43,806
Deferred income taxes (1)	**166,817**	164,079	2,738
	$ 417,173	**$ 366,208**	**$ 50,965**
Regulatory Liabilities			
Weather normalization account	**$ 6,549**	$ 9,108	$ (2,559)
Future removal and site restoration provision (1)	**126,329**	122,947	3,382
Demand management incentive account	**785**	1,801	(1,016)
	$ 133,663	$ 133,856	$ (193)

(1) 2011 actual balances have been revised from the balances that were presented in the 2011 annual report to account for presentation changes including the adoption of US GAAP as approved by the Board in P.U. 27 (2011).

Rate stabilization

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, 2012 were approved by the Board in P.U. 20 (2012). The RSA regulatory asset of $19,529,000 represents a current portion of $13,912,000 and a non-current portion of $5,617,000.

As of December 31, 2012, there was a charge to the RSA of $9,727,000 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007) and P.U. 43 (2009).

Pursuant to 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, 2012, the credit balance of $488,420 in the OPEBVDA account was credited to the RSA in accordance with P.U. 31(2010).

Pursuant to 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, 2012, the balance of $3,863,268 in the PEVDA account was credited to the RSA in accordance with P.U. 43 (2009).

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 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 P.U. 31(2010).

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. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year. As at December 31, 2012, the non-reversing Degree Day component has been fully amortized. The balance in the Weather Normalization reserve represents the reversing component, which should tend to zero over time. The net balance in the Weather Normalization reserve at December 31, 2012 is a net regulatory liability of $6,549,000 (net of future income taxes, the balance is $4,803,404).

Pension deferral

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004).

Deferred pension costs include $2,537,000 related to a pension deferral which is included with Regulatory Assets in the Company's financial statements. The net change in this account represents the difference between employer contributions and pension expense during 2012.

Cost recovery deferral

The Cost Recovery Deferral balance relates to the conclusion of the following regulatory amortizations which expired in 2010: 2005 Unbilled Revenue, Municipal Tax Liability, Depreciation, Replacement Energy, Purchased Power Unit Cost Reserve and 2008 GRA Costs. Expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000. On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of the above mentioned deferrals. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 46(2009). In P.U. 30 (2010), the Board approved the deferred recovery, until a further

Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which is to be charged with the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differ from the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. In P.U. 22 (2011), the Board approved the deferred recovery, until a further Order of the Board, of an additional $2,363,000 in 2012 due to the conclusion in 2010 of the amortizations. The disposition of the $4,726,000 balance in this account will be determined by a further order of the Board.

Cost of capital cost recovery deferral

The cost of capital cost recovery deferral account reflects the deferred recovery of $2,487,000 reflecting the difference between the 8.38% return on equity currently in customer electricity rates and the 8.80% return on equity approved in P.U. 17 (2012). The disposition of this balance is the subject of a future board order.

Deferred general rate application costs

As noted in the 2010 Annual Review Report, the Company deferred $760,000 of costs relating to the 2010 GRA. According to P.U. 43 (2009) the Board approved the amortization of a total amount of $750,000 over a three year period commencing January 1, 2010 and in P.U. 26 (2011) the Board ordered Newfoundland Power to adjust its 2011 rate base with respect to the recovery of hearing costs recorded in 2010 to reflect the originally approved $750,000. In 2012 this balance has been fully amortized.

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 P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In 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.

Optional seasonal rate revenue and cost recovery account

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2012 was $129,795. This balance was transferred to the RSA on March 31, 2013 pursuant to the Board's approval in P.U. 10 (2013).

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 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 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). As of December 31, 2012 the balance in this account was $175,056,000.

Deferred income taxes

Deferred income tax assets and liabilities associated with 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, 2012 was $166,817,000. The 2011 comparative balance was restated to reflect the impact of the adoption of US GAAP and as a result the balance was $164,079,000. This restatement did not impact the rate base or return on average rate base.

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.

In 2012, the Company adopted a change in presentation for the regulatory liability for the future removal and site restoration provision. Prior to December 31, 2012, the regulatory provision for future removal and site restoration costs, net of tax and salvage, for property, plant and equipment was recorded as a long-term regulatory liability. Actual costs of removal and site restoration incurred, net of tax and salvage proceeds, were recorded against this regulatory liability. The Company has changed the presentation of (i) the accumulated tax effects related to future removal and site restoration costs from a long-term regulatory liability to long-term deferred income taxes; and (ii) the accumulated salvage from a long-term regulatory liability to accumulated depreciation. This change was applied retroactively, with restatement of the 2011 comparative balances. This change in presentation had no impact on the rate base or return on average rate base. For 2012 the balance in this account was $126,329,000 (2011 - $122,947,000).

Demand management incentive account

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2012, the variation in the account was $785,446. This balance was transferred as a credit to the RSA on March 31, 2013 pursuant to the Board's approval in P.U. 8 (2013).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2012 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account ("PEVDA") and assess compliance with P.U. 43 (2009)***

In 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 2012 PEVDA was calculated at $3,863,268. This balance was transferred to the Rate Stabilization Account on March 31, 2012 in accordance with P.U. 43 (2009).

We confirm that the 2012 PEVDA is calculated in accordance with 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 P.U. 31(2010)***

In 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 2012 OPEBVDA was calculated at $488,420. This balance was transferred to the Rate Stabilization Account on March 31, 2012 in accordance with P.U. 31 (2010).

We confirm that the 2012 OPEBVDA is calculated in accordance with P.U. 31 (2010).

Optional Seasonal Rate Revenue and Cost Recovery Account

Scope: ***Review of calculation of the Optional Seasonal Rate Revenue and Cost Recovery Account and assess compliance with P.U. 8 (2011)***

In P.U. 8 (2011) the Board approved Rate #1.1S Domestic Seasonal – Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates (the "TOD Rate Study"). On December 31st of each year from 2011 until further order of the Board, this account is to 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 accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the first day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. This application for the disposition of the 2012 balance was filed February 15, 2013, within the deadline.

The Optional Seasonal Rate Revenue and Cost Recovery Account balance at December 31, 2012 was $129,795. This balance was transferred to the Rate Stabilization Account in March, 2013 as approved in P.U. 10 (2013).

We confirm that the 2012 Optional Seasonal Rate Revenue and Cost Recovery Account is calculated in accordance with P.U. 8 (2011).

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 2012 are as follows:

1. The Company continued with mobile technologies projects, installing computers in additional trucks in the fleet.

2. Maintained a Power Line Technician Apprentice Program to facilitate transfer of critical knowledge from senior employees.

3. Replaced over 475 transformers with stainless steel units.

4. The Company continued to install automated meters with remote capabilities in locations that prove difficult to read. Twenty-eight meter reading routes were eliminated in 2012.

5. Redesigned the Interactive Voice Response telephone system to provide improved call routing, so that customers are directed to those Contact Centre staff best equipped to respond to the customer's request.

6. The Contact Centre commenced troubleshooting for all Radio Frequency Interference calls. This allows customers to have their Radio Frequency Interference issues addressed with one phone call.

7. Implemented automated information updates from the Company's website to report a street light outage. The information entered by the customer is automatically updated in the Company's outage system and no longer requires manual data entry.

8. Updated the Company's mobile web site with the capability for account balance lookup and display of e-Bills. Customers now have the ability to update their phone numbers via the Company's web site, eliminating the need for an agent to complete the updates in the Customer Service System.

9. The Company continues to promote e-Bills. At year end 2012 approximately 54,700 customers, representing 22% of all customers, received their bills electronically.

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 of the company:

Category	Measure	Actual 2010	Actual 2011	Actual 2012	Plan 2012	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.59	2.57	2.44	2.60	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.52	1.70	1.72	1.95	Yes
	Plant Availability (%)	96.8	93.5	94.8	96.5	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	89.3	88.5	86.7	88.5	No
	Call Centre Service Level (% per second)[2]	78/60	80/60	80/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	82.7	80.2	84.5	85.0	No
Safety	All Injury/Illness Frequency Rate	1.9	1.8	1.7	1.6	No
Financial	Earnings (millions)[3]	$35.0	$33.7	$36.6	$33.3	Yes
	Gross Operating Cost/Customer[4]	$234	$241	$238	$233	No

[1] 2012 reliability statistics reported above exclude the impact of Tropical Storm Leslie. 2011 reliability statistics exclude the impact of a storm in December 2011. 2010 reliability statistics exclude the impact of the March 2010 ice storm and Hurricane Igor

[2] In 2010, Customer Service changed how it monitors answered calls. Service level is now based on calls answered in 60 seconds as opposed to 40 seconds in the original plan.

[3] 2012 Plan has been adjusted to reflect the 8.8% allowed rate of return on common equity for 2012.

[4] Excluding pension, OPEBs and early retirement costs.

Grant Thornton
2013 Annual Financial Review of Newfoundland Power Inc.

Board of Commissioners of Public Utilities
2013 Annual Financial Review of Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2013 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 2013 was $915,820,000 compared to average rate base for 2012 of $883,045,000 and 2013 Test Year of $918,716,000. The Company's calculation of the return on average rate base for 2013 was 8.10% (2012 - 8.10%) compared to an approved rate of return of 7.92%. The actual rate of return was the maximum of the range approved by the Board (7.74% to 8.10%). 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 2013 was $414,578,000 (2012 - $395,793,000). The Company's actual return on average common equity for the year ended December 31, 2013 was 9.16% (2012 – 8.98%). In 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 2013 the cost of common equity per the Formula was 8.8% (P.U. 13 (2013)). The actual return on average common equity for 2013 was 9.16% 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) was 0.96% under budget in 2013. The capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $2,544,000 (2.74%). However, for each category of expenditure, the variances ranged from an over-budget of 10.18% to an under-budget of 85.81%. Significant variances are explained in our report.

The Company experienced a 4.57% increase in revenue from rates in 2013 as compared to 2012. The increase can be explained by higher electricity sales and the rebasing of customer rates effective July 1, 2013 due to the implementation of 2013/14 GRA order.

Net operating expenses in 2013 increased by $2,351,000 from 2012 and $3,009,000 over the 2013 Test Year. The increase is primarily due to an increase in labour, pension and the accrual of other post-employment benefits ("OPEBs"). These and other 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 2013 are unreasonable.

Non-regulated expenses, net of tax, decreased in 2013 by ($10,274,000). This variance was largely explained by a change of $10,225,000 (credit) in the Part VI.1 tax adjustment allocated by Fortis Inc. among its subsidiaries.

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 2013 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

Based on our review, the 2013 Other Post Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with P.U. 31 (2010).

Based on our review, the 2013 Optional Seasonal Rate Revenue and Cost Recovery Account operated in accordance with P.U. 8 (2011).

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 2013 the Company met six out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Outage/Customer (SAIFI) – excluding Hydro loss of supply", "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey". The Company excluded the impact of the January Newfoundland and Labrador Hydro system problems and the November blizzard in Central and Western.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2013 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,
   - demand side 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 P.U. 19 (2003) and P.U. 32 (2007).

5. Examine the Company's 2013 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 2013 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 P.U. 43 (2009) and P.U. 16 (2013).

11. Conduct an examination of the OPEBs Cost Variance Deferral Account and the amortization of the Company's transitional balance to assess compliance with P.U. 31 (2010) and P.U. 16 (2013).

12. Conduct an examination of the Optional Seasonal Rate Revenue and Cost Recovery Account compliance with P.U. 8 (2011) and P.U. 10 (2013).

13. Conduct an examination of the deferred cost recovery relating to the 2012 Cost of Capital in compliance with P.U. 17 (2012) and its amortization in compliance with P.U. 13 (2013).

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;
- examination of, on a test basis where appropriate, documentation supporting amounts included in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

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, 2013 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 5, 2014. 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 28, 2014, the Company filed a revised system of accounts as part of its 2013 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, 2013 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 2013 was $915,820,000 compared to forecast average rate base for 2013 test year of $918,716,000 as approved during the 2013 GRA in P.U. 13 (2013). The decrease of $2,896,000 (0.32%) below test year is primarily a result of future income taxes below those forecasted. The average rate base for 2012 was $883,045,000.

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 2013; 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 2013, 2013 test year and 2012 (all figures shown are averages):

(000)'s	2013	2013 Test Year	2012
Net Plant Investment (average)			
Plant Investment	$1,470,688	$1,459,551	$ 1,405,709
Accumulated Depreciation	(613,131)	(604,378)	(589,318)
CIAC's	(31,459)	(31,734)	(30,010)
	826,098	823,439	786,381
Additions to Rate Base (average)			
Deferred Charges (a)	100,756	101,680	99,125
Cost Recovery Deferral for Seasonal/TOD Rates (b)	94	136	160
Cost Recovery Deferral for Hearing Costs (c)	322	417	127
Cost Recovery Deferral for Regulatory Amortizations (d)	2,767	2,767	2,481
Cost Recovery Deferral – 2012 Cost of Capital (e)	1,472	1,471	883
Cost Recovery Deferral – 2013 Revenue Shortfall (f)	1.126	1,126	-
Cost Recovery Deferral – Conservation (g)	1,156	1,202	341
Customer Finance Programs (h)	1,405	1,466	1,487
	109,098	110,265	104,604
Deductions from Rate Base (average)			
Weather Normalization Reserve (i)	4,931	4,861	4,912
2010 Hearing Costs Adjustment	-	-	3
Other Post Employment Benefits (j)	19,066	18,257	10,908
Customer Security Deposits (k)	846	830	773
Accrued Pension Obligation (l)	4,173	4,189	3,899
Deferred Income Taxes (m)	2,188	(1,877)	1,683
Demand Management Incentive Account (n)	143	421	905
	31,347	26,681	23,083
Average Rate Base before Allowances	903,849	907,023	867,902
Rate Base Allowances			
Materials and Supplies	5,445	6,553	5,332
Cash Working Capital	6,526	5,140	9,811
	11,971	11,693	15,143
Average Rate Base	$ 915,820	$ 918,716	$ 883,045

(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 $100,756,000 (2012 - $99,125,000) included in the 2013 rate base consists of average deferred pension costs of $100,636,000 (2012 - $98,871,000) and credit facility costs of $120,000 (2012 - $255,000). The Company has included a schedule of these costs in Return 8.

(b) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to 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". The calculation of the 2013 average rate base incorporates $94,000 (2012 - $160,000) related to this deferral account.

(c) In P.U. 13 (2013) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2013, hearing costs related to the 2013/2014 GRA in the amount of $1,250,000. During 2013, the Company deferred $965,000, $285,000 lower than the approved amount, of 2013/2014 GRA hearing costs. The average rate base includes an addition of $322,000 (2012 - $127,000) which represents the unamortized average balance of the original $965,000.

(d) On August 31, 2010 Newfoundland Power submitted an application proposing to defer recovery, until a further Order of the Board, of the amount of $2,363,000 ($1,642,000 after tax) in 2011 to offset the net impact of the expiring amortizations relating to the Municipal Tax Liability, Unrecognized 2005 Unbilled Revenue, Deferred Energy Replacement Costs and the Purchased Power Unit Cost Variance Reserve. This application was approved by the Board in P.U. 30 (2010). P.U. 22 (2011) approved the deferral in 2012 of an additional $2,363,000 ($1,678,000 after tax) related to these expiring amortizations. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Included in the calculation of the average rate base for 2013 is $2,767,000 (2012 - $2,481,000) related to this deferral.

(e) In P.U. 17 (2012) the Board approved the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Included in average rate base is $1,472,000 (2012 - $883,000) related to this deferral.

(f) In P.U. 13 (2013) the Board approved the deferral and amortization over three years of amounts related to Newfoundland Power's shortfall in the recovery of revenue requirements for 2013. As a result of this order and updated revenue forecasts subsequently filed by Newfoundland Power in an *Application Filed in Compliance with Order No. P.U. (2013)*, an amount of $3,965,000 ($2,815,000 after tax) has been deferred. Based on a rate implementation date of July 1, 2013, the amortization period has subsequently been updated to 30 months, resulting in amortization for 2013 of $563,000. Included in the calculation of average rate base for 2013 is $1,126,000 related to this deferral.

(g) In P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan. These costs were fully amortized in 2013. In 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) with annual amortization of this amount of $298,000 to commence in 2014. Included in the calculation of the average rate base for 2013 is $1,156,000 related to this deferral.

(h) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2013 average rate base incorporates $1,405,000 (2012 - $1,487,000) related to these programs.

(i) During 2013, the Weather Normalization reserve was impacted by the following:

Transfer to RSA

i. In 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 $216,000 in 2013.

Other transfers:

i. $393,000 transfer (increase) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $1,319,000 transfer (increase) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

Amortization

i. Also in P.U. 13 (2013) the Board approved a three year amortization of the 2011 balance in the Weather Normalization Reserve of $5,020,000 resulting in a decrease to the reserve of $1,673,000 of amortization for 2013.

The net impact was a net increase to the reserve of $255,000. The ending balance in this reserve account totaled $5,058,000 compared to a balance of $4,803,000 at December 31, 2012 (an average of $4,931,000 for 2013).

(j) Other Post-Employment Benefits is equal to the difference, at December 31, 2013, between the OPEBs liability of $65,563,000 and the OPEBs asset of $42,048,000. The calculation of the 2013 average rate base is equal to the average of the December 31, 2013 net liability of $23,515,000 and the December 31, 2012 net liability of $14,617,000.

(k) 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 2013 average rate base incorporates $846,000 (2012 - $773,000) related to customer security deposits.

(l) The 2013 average rate base calculation incorporates $4,173,000 (2012 - $3,899,000) 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.

(m) In 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 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 2013 average rate base is $1,017,000 and ($5,202,000) respectively. The remaining balance of the deferred income tax liability in the amount of $6,373,000 relates to capital assets. This results in an average balance for deferred income tax liability of $2,188,000. The average test year balance for 2013 was ($1,877,000), a variance from actual of $4,065,000. The primarily reason for this variance relates to the difference in pension funding in 2012 with an actual of $15,970,000 in funding compared to test year forecast for 2012 of $5,363,000 in funding.

(n) In P.U. 32 (2007) the Board approved the Company's proposal to establish the Demand Management Incentive Account. In P.U. 8 (2013) the Board approved the disposition of the 2012 balance of the Demand Management Incentive Account of $785,446 (less the related income tax) by means of a credit to the Rate Stabilization Account as of March 31, 2013. In P.U. 7 (2014) the Board approved the disposition of the 2013 balance of the Demand Management Incentive Account of $383,085 (less the related income tax) by means of a debit to the Rate Stabilization Account as of March 31, 2014.

The net change in the Company's average rate base from 2012 to 2013 can be summarized as follows:

(000's)	2013	2012
Average rate base - opening balance	**$ 883,045**	$ 876,356
Change in average deferred charges and deferred regulatory costs	**4,575**	881
Average change in:		
Plant in service	**64,979**	22,922
Accumulated depreciation	**(23,813)**	(8,685)
Contributions in aid of construction	**(1,449)**	(370)
Weather normalization reserve	**(19)**	(1,425)
Other post employment benefits	**(8,158)**	(7,308)
Future income taxes	**(505)**	556
Rate base allowances	**(3,172)**	468
Other rate base components (net)	**337**	(350)
Average rate base - ending balance	**$ 915,820**	$ 883,045

Based upon the results of the above procedures we note the following:

The average rate base of $915,820,000 was subsequently filed in Schedule D of its 2015 Capital Budget Application and differs from the average rate base of $915,612,000 as filed in Return 3 of the Company's 2013 Annual Report to the Board. The revisions included on Schedule D resulted in an overall increase of $208,000 in average rate base as compared to Return 3 due to the following:

- **An increase in materials and supplies allowance of $272,000 as, according to the Company, Return 3 material and supplies allowance understated the final material and supplies costs in 2013 included in Schedule D.**

- **A decrease of $64,000 resulting from the exclusion of deferred credit facility costs in Schedule D. The deferred credit facility costs are included as a component of the Company's weighted average cost of capital and are excluded from the average rate base calculation. Return 3 included the deferred credit facility costs in error.**

Other than the items previously discussed, we did not note any discrepancies in the calculation of the 2013 average rate base included in Return 3 of the Company's Annual Returns and we conclude that the average rate base of $915,820,000 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 2013 (based on the revised average rate base of $915,820,000 filed in Schedule D of its 2015 Capital Budget Application) was 8.10% (2012 - 8.10%). 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 2013, the return on average rate base is calculated in accordance with the methodology approved in 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 2011 to 2013 is set out in the table below.

	2013	**2012**	**2011**
Actual Return on Average Rate Base	8.11%	8.10%	8.14%
Upper End of Range set by the Board	8.10%	8.32%	8.14%
Lower End of the Range set by the Board	7.74%	7.96%	7.78%

The Board approved the Company's rate of return on average rate base of 7.92% in a range of 7.74% to 8.10% for 2013 in P.U. 13 (2013). As noted above, the Company's actual return on average rate base for 2013 was 8.11% which was outside the range set by the Board. The actual rate of return for 2011 and 2012 were both within the range set by the Board.

As the rate of return on average rate base is outside the range set by the Board the Company has recorded a regulatory liability and decrease in earnings in the amount of $68,000 ($49,000 after tax). As a result of the revised average rate base we calculated excess earnings of $42,000 ($33,000 after tax). In discussions with the Company they have determined the additional excess earnings of $26,000 ($16,000 after tax) reported in Return 13 are immaterial to file a revised return. This represents a benefit to the customer. See 'Regulatory Assets and Liabilities' section of our report for further details.

As a result of completing these procedures, we can advise that no discrepancies were noted except as described above relating to excess earnings 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 P.U. 13 (2013) the Board reconfirmed its previous position as per P.U. 43 (2009) 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 2013 as reported in Return 24 is as follows:

	2013 Average		2012	2011
	(000's)	**Percent**	Percent	Percent
Debt	**$504,185**	**54.35%**	54.47%	54.22%
Preferred equity	**9,031**	**0.97%**	1.02%	1.04%
Common equity	**414,578**	**44.68%**	44.51%	44.74%
	$927,794	**100.00%**	100.00%	100.00%

Pursuant to 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 2013 test year in Return 26. The embedded cost of debt for 2013 was 7.24% which represents a 1 bps increase from 2013 test year embedded cost of debt of 7.23%.

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 Board Order P.U. 13 (2013).

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, 2013 is included on Return 27 of the annual report to the Board. The average common equity for 2013 was $414,578,000 (2012 - $395,793,000). The Company's actual return on average common equity for 2013 was 9.16% (2012 – 8.98%).

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 P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007), P.U. 43(2009) and P.U. 13 (2013).
- recalculated the rate of return on common equity for 2013 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 13 (2013).

In 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 2013 the cost of common equity was 8.80% as per P.U. 13 (2013). The actual return on average common equity for 2013 was 9.16% 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 two years is as follows:

(000's)	2013	2012
Net income	**$ 49,920**	$ 37,204
Income taxes	**(2,877)**	10,861
Interest on long term debt	**35,123**	35,039
Interest during construction	**(893)**	(820)
Other interest and amortization of debt discount costs	**1,377**	1,258
Total	**$ 82,650**	$ 83,542
Interest on long term debt	**$35,123**	$ 35,039
Other interest and amortization of debt discount costs	**1,377**	1,258
Total	**$36,500**	$ 36,297
Interest Coverage (times)	**2.3**	2.3

The above table shows that the interest coverage did not change from 2012 to 2013.

In 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 2013 is 2.3 times.

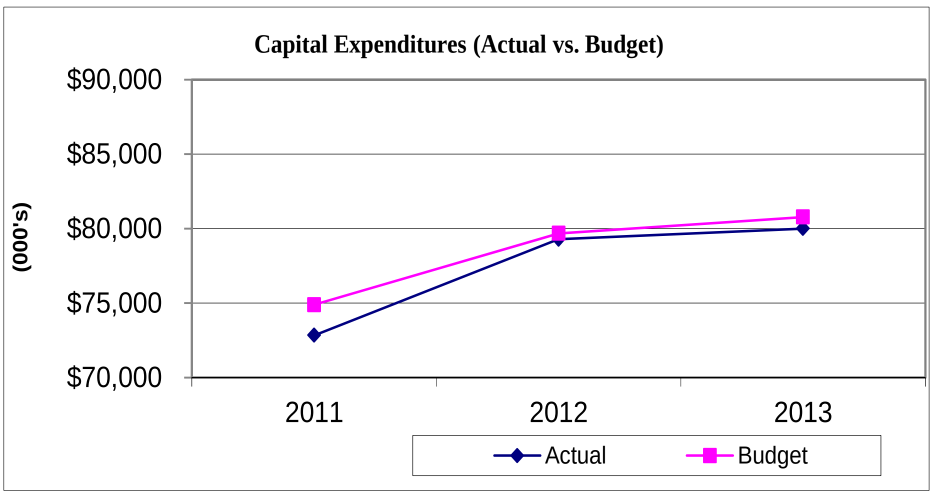
Capital Expenditures

Scope: ***Review the Company's 2013 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 2011 to 2013.

(000's)	**2011**	**2012**	**2013**
Actual	$ 72,846	$ 79,290	**$ 80,013** (1)
Budget	$ 74,894	$ 79,690	**$ 80,788**
Over (under) budget	(2.73%)	(0.50%)	**(0.96%)**

(1) Total expenditures per the 2013 Capital Budget report include the carryover amount of $4,315,000 for a total of $84,148,000. The carryover amount is made up of three projects: $2,675,000 relating to substations, $710,000 relating to general property and $750,000 relating to telecomminications. According to the Company, these expenditures will occur in 2014.



The following table provides a summary of the capital expenditure activity in 2013 as reported in the Company's *"2013 Capital Expenditure Report"*.

	Capital Budget			Actual Expenditures		
(000's)	**2010-2012**	**2013**	**Total**	**2010-2012**	**2013**	**Total**
2013 Capital Projects and GEC (1) and (7)	$ -	$ 80,788	**$ 80,788**	$ -	$80,013	**$80,013**
<u>2010, 2011 and 2012 Projects carried to 2013</u>						
Rattling Brook Fisheries Compensation – 2012 (2)	5,000	-	**5,000**	2,744	213	**2,957**
Feeder Additions for Growth – 2012 (3)	1,391	-	**1,391**	1,486	59	**1,545**
Trunk Feeders – 2012 (4)	848	-	**848**	779	285	**1.064**
Company Building Renovations - 2012	935	-	**935**	620	392	**1,012**
Feeder Additions for Growth – 2011 (5)	1,281	-	**1,281**	633	1,202	**1,835**
Feeder Additions for Growth - 2010	465	-	**465**	188	198	**386**
Additions Due to Load Growth – Multi Year	1,156	-	**1,156**	1,195	-	**1,195**
Portable Substation – Multi Year (6)	879	-	**879**	192	-	**192**
	11,955	-	**11,955**	7,837	2,349	**10,186**
	$11,955	$80,788	**$92,743**	$7,837	$82,362	**$90,199**

(1) Approved by Order P.U. 31 (2012).

(2) The Company has noted that the favorable variance to budget relates to the remaining portions of a project implementation plan covering a 5 year period 2012 to 2016, directed by the Department of Fisheries and Oceans.

(3) The total budget for the 2012 Feeder Additions for Growth was $1,391,000. Total expenditures were $1,545,000 which is $154,000 above budget. The Company notes the majority of the variance is principally due to the purchase of an underground cable that was $100,000 higher than anticipated in the budget.

(4) The total budget for the 2012 Trunk Feeders project was $848,000. Total expenditures were $1,064,000 which is $216,000 above budget. The variance was caused by additional expenditures incurred to comply with municipal requirements as well as federal government requirements under the Parks Canada Environmental Protection Plan.

(5) The total budget for the 2011 Feeder Additions for Growth was $1,281,000. Total expenditures were $1,835,000 which is $554,000 above budget. The variance to budget was caused by upgrades to feeders that occurred over longer distances than originally estimated (approximately $327,000 of the variance). Additional variances were caused by property owner permissions that required revised distribution systems and routes which resulted in additional project expenditures of $150,000.

(6) The Company has noted the amounts provided in the 2012 Capital Budget Application estimated an expenditure of $879,000 in 2012 and $3,621,000 in 2013 for a total project estimate of $4,500,000. In the 2013 Capital Budget Application, the budget for 2013 was reduced to $3,121,000, lowering the total project budget estimate to $4,000,000. The order for the portable substation was placed in 2012 with delivery expected in April 2014. Actual expenditures of $192,000 and $638,000 have been incurred for the years 2012 and 2013 respectively, with a $2,600,000 carryover of expenditures to 2014 for a combined total of $3,430,000. Compared to the total project budget of $4,000,000, there is a favorable variance of $570,000. This reduction in project cost was the result of the tendered supply contract being lower than the original engineering estimate.

(7) Total expenditures per the 2013 Capital Budget include the carryover amount of $4,135,000 for a total of $84,148,000. See note 1 on the previous page.

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

(000's)	2013 Budget [1]	2013 Actuals	Variance	%
Generation - Hydro	$ 9,450	$ 7,264 [2]	$ (2,186)	(23.13%)
Generation - Thermal	284	201	(83)	(29.23%)
Substations	19,653	15,065	(4,588)	(23.35%)
Transmission	5,371	5,444 [2]	73	1.36%
Distribution	42,725	46,806 [2]	4,081	9.55%
General property	2,672	2,858	186	6.96%
Transportation	2,950	3,220	270	9.15%
Telecommunications	874	124	(750)	(85.81%)
Information systems	4,014	4,312	298	7.42%
Unforeseen	750	498	(252)	(33.60%)
General expenses capitalized	4,000	4,407	407	10.18%
Total	$ 92,743	$ 90,199	$ (2,544)	(2.74%)

1 -Includes prior years (2010 to 2012) and current year budgeted amounts as there were projects incomplete at the previous year ends. The 2013 budget for Generation - Hydro includes $5,000,000 carried forward from the 2012 budget relating to Rattling Brook Fisheries Compensation. The 2013 budget for Substations includes $879,000 carried forward from the 2012 budget relating to Portable Substation and $1,156,000 relating to Additions Due to Load Growth. The 2013 budget for Distribution includes $1,391,000, $1,281,000 and $465,000 for Feeder Additions for Growth carried forward from the budgets for the years 2012, 2011 and 2010 respectively. In addition, it includes $848,000 for Trunk Feeders carried forward from the 2012 budget. The 2013 budget for General property includes $935,000 carried forward from the 2012 budget for Company Building Renovations.

2 - 2012 actuals include the total expense for projects carried forward from the years 2010 to 2012. Total costs for Generation - Hydro includes the carry forward for Rattling Brook Fisheries Compensation costs of which $2,744,000 was spent in 2012 with a further $213,000 spent in 2013. Total costs for Substations include the carry forward for a Portable Substation costs of which $192,000 was spent in 2012 with a further $638,000 spent in 2013. Substations also include the carry forward for Additions Due to Load Growth costs of which $1,195,000 was spent in 2012 with a further $2,705,000 spent in 2013. Total costs for Distribution includes the carry forward for: 1) Feeder Additions for Growth (2012) of which $1,486,000 was spent in 2012 with a further $59,000 spent in 2013. 2) Feeder Additions for Growth (2011) of which $633,000 was spent in 2012 with a further $1,202,000 spent in 2013. 3) Feeder Additions for Growth (2010) of which $188,000 was spent in 2012 with a further $198,000 spent in 2013. Total costs for Distribution also include the carry forward for Trunk Feeders of which $779,000 was spent in 2012 with $285,000 spent in 2013. General property includes carry forwards for Company Building Renovations of which $620,000 was spent in 2012 with an additional $392,000 spent in 2013.

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 $2,544,000 (2.74%). However, for each category of expenditure, the variances ranged from an over-budget of 10.18% to an under-budget of 85.81%. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. In addition, the Company has noted that there is $4,135,000 related to projects that will be carried forward to 2013 which include Station Refurbishment and Modernization ($75,000), Company Building Renovations ($550,000), Stand-by and Emergency Power – Duffy Place ($160,000), Mobile Radio System Replacement ($750,000) and Portable Substation ($2,600,000). The explanations provided by the Company indicate that the capital expenditure variances for 2013 were caused by a number of factors. The Company has provided detailed explanations on budget to actual variances in its "2013 Capital Expenditure Report". For a complete review of the budget variance we refer the reader to this report, Appendix A.

The more significant variances noted above were as a result of the following:

Generation - Hydro

- The favorable variance of $2,186,000 is primarily due to an extended implementation period of the *Rattling Brook Dam Replacement* project, resulting in a 2013 variance of $2,043,000, with work to be completed over a 5-year period from 2012 to 2016.

Substations

- The favorable variance of $4,588,000 is due to the carry forward to 2014 of $2,600,000 of expenditures related to *Substation Additions – Portable Substation*. In addition the purchase price of the portable substation was $570,000 lower than budget as the result of a tendered supply contract that was lower than the original engineering estimate. Favorable variances of $1,230,000 resulted from *Additions Due to Load Growth (2012-2013 Glendale Substation)* as a result of prices obtained through tendering that were lower than original engineering estimates.

Distribution

The unfavorable variance in Distribution of $4,081,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 11,376	$ 13,434	$ 2,058	18.09%
Meters	2,849	3,109	$ 260	9.13%
Services	3,705	4,280	$ 575	15.52%
Street Lighting	2,267	2,592	$ 325	14.34%
Transformers	7,983	6,710	$ (1,273)	(15.95%)
Reconstruction	3,499	4,643	$ 1,144	32.70%
Rebuild Distribution Lines	2,997	2,958	$ (39)	(1.30%)
Relocate/Place Distribution Lines for Third Parties	2,554	2,586	$ 32	1.25%
Trunk Feeders	117	154	$ 37	31.62%
2012 Feeder Additions for Growth	1,204	1,314	$ 110	9.14%
AFUDC	189	196	$ 7	3.70%
Feeder Addtions for Growth (2012)	1,391	1,545	$ 154	11.07%
Feeder Addtions for Growth (2011)	1,281	1,835	$ 554	43.25%
Feeder Addtions for Growth (2010)	465	386	$ (79)	(16.99%)
Trunk Feeders (2012)	848	1,064	216	25.47%
Total	$ 42,725	$ 46,806	$ 4,081	9.55%

- The unfavorable variance in "Extensions" of $2,058,000 is primarily due to higher than anticipated customer growth which resulted in additional new customer connections that exceeded budgets based on five year historical averages.

- The unfavorable variance in "Services" of $575,000 is primarily due to higher than anticipated customer growth which resulted in additional new customer connections that exceeded budgets based on five year historical averages.

- The unfavorable variance of $325,000 in "Street Lighting" is a result of higher than anticipated new customer connections as compared to budgeted figures.

- The favorable variance of $1,273,000 in “Transformers” was a result of lower than anticipated contract prices.

- The unfavorable variance of $1,144,000 in “Reconstruction” is attributed to a higher than expected amount of work completed under this project. The number of high priority projects that required immediate attention was higher than the budgets based on historical 5-year average.

- The unfavorable variance of $154,000 in “2012 Feeder Additions for Growth” is due primarily to the purchase price of an underground XLPE cable which was $100,000 higher than anticipated.

- The unfavorable variance of $554,000 in “2011 Feeder Additions for Growth” is due primarily to the need to complete upgrades over a longer distance along the feeder than was anticipated in the initial project estimate ($327,000 unfavorable variance). Additional unfavorable variances of $150,000 were caused by delays in obtaining property owner permission that required a revised distribution system and an aerial feeder route which resulted in additional project expenditures.

Telecommunications

- The favorable variance of $750,000 is due to a budgeted expenditure of $750,000 for the *Mobile Radio System Replacement* project which has been carried forward to 2014.

Allowance for Unforeseen Items

- The favorable variance of $252,000 is due to unforeseen expenditures that were lower than budgeted. During 2013 the Company spent $498,000 of the $750,000 budget to correct damages to the electricity system in Central Newfoundland caused by a winter storm on November 21, 2013.

General expenses capitalized

- The unfavorable variance of $407,000 is related to an increase in the allocated portion of pension expense. Pension expenses increased as a result of the amortization of 2008 losses associated with the pension plan assets, along with a lower discount rate being used to determine the Company’s accrued obligation under its defined benefit pension plan. The discount rate used for the year ended December 31, 2013 was 4.4% compared to 5.3% used for the year ended December 31, 2012.

Adherence to Capital Budget Application Guidelines

Based on our review, the Company’s 2013 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 (0.50%) in 2012 and (0.96%) in 2013 resulting in no additional reporting requirements.

Based on our review, the Company's 2013 reporting with respect to allowance for unforeseen items was not in accordance with the Capital Budget Application Guidelines Policy #1900.6 Section B as noted below:

- Under Section B, the Company used the Allowance for Unforeseen Items account to expeditiously deal with an event affecting the electrical system which could not wait for Board approval. On November 21, 2013 an unforeseen expenditure of $498,000 was required to repair damages caused by a severe winter storm in Central Newfoundland. A report entitled *November 2013 Winter Storm Central Newfoundland, March 2014* was submitted March 21, 2014. Under Section B, the final report must be submitted within 30 days of the completion of the work on the unforeseen expenditure, which in this case was December 24, 2013. The report related to the Central Newfoundland Winter Storm, submitted on March 21, 2014, was submitted over 30 days after the completion of work.

<u>Capital Expenditure Reports</u>

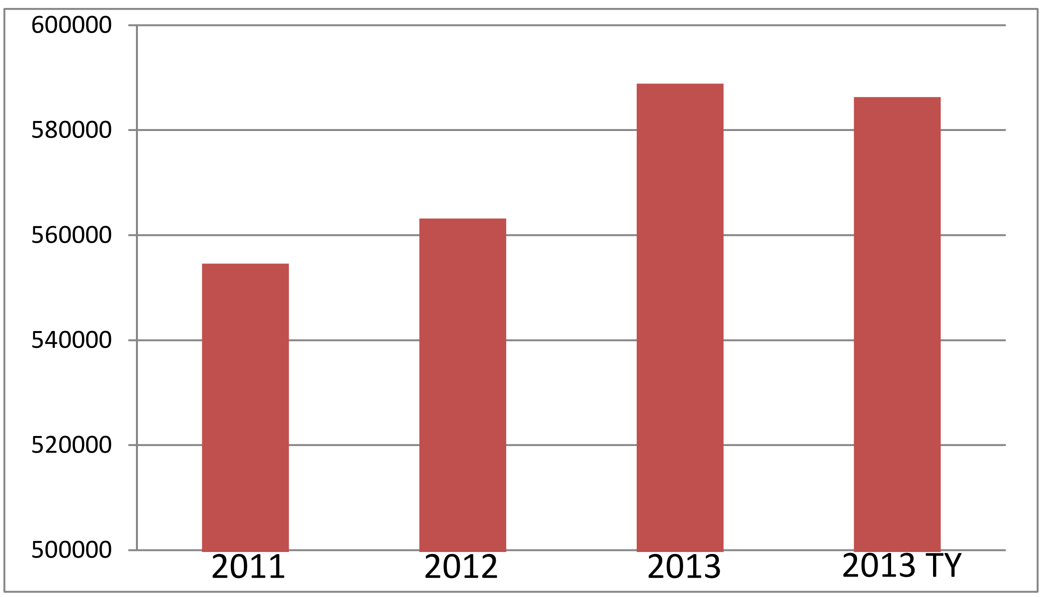
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2013 calendar year.

Revenue

Scope: ***Review the Company's 2013 revenue in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues for 2011 to 2013 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2011	2012	**2013**	**2013 Test Year**
Residential	$ 344,609	**$ 348,325**	**$ 367,550**	**$ 367,576**
General services				
0-10kW	12,568	**12,890**	**12,853**	**12,863**
10-100kW	67,341	**67,938**	**68,772**	**68,518**
110-1000kVA	79,954	**80,641**	**83,223**	**83,477**
Over 1000kVA	31,500	**34,664**	**36,961**	**36,112**
Street lighting	13,867	**13,968**	**14,633**	**14,525**
Forfeited discounts	2,719	**2,737**	**2,844**	**3,239**
Revenue from rates	$ 552,558	$ 561,163	**$ 586,836**	**$ 586,310**
Year over year percentage change	3.22%	1.56%	**4.57%**	**-0.09%**



The above graph demonstrates that the Company has seen a 4.57% increase in revenue from rates in 2013 as compared to 2012. The increase reflects higher electricity sales and the rebasing of customer rates effective July 1, 2013 due to the implementation of 2013/14 GRA order. There was a 1.96% increase in the overall demand in GWh for 2013. For residential sales there was an increase of 5.52% in 2013 revenue from 2012. GWh sold in this category increased by 2.59%, and the number of residential customers increased by 1.70%.

The comparison by rate class of 2013 actual revenues to 2013 Test Year is as follows:

(000's)	Actual 2012	Actual 2013	Test Year 2013	Actual - Test Year Variance	%
Residential	$ 348,325	$ 367,550	$ 367,576	$ (26)	-0.01%
General service					
0-10kW	12,890	12,853	12,863	(10)	-0.08%
10-100kW	67,938	68,772	68,518	254	0.37%
110-1000kva	80,641	83,223	83,477	(254)	-0.30%
Over 1000kva	34,664	36,961	36,112	849	2.35%
Street lighting	13,968	14,633	14,525	108	0.74%
Forfeited discounts	2,737	2,844	3,239	(395)	-12.20%
Total revenue from rates	$ 561,163	$ 586,836	$ 586,310	$ 526	0.09%

We have also compared the 2013 test year forecast energy sales in GWh to the actual sold in 2013.

	Actual 2012	Actual 2013	Test Year 2013	Actual - Test Year Variance	%
Residential	3,441.5	3,530.6	3,532.4	(1.8)	-0.05%
General service					
0-10kW	96.4	97.5	97.8	(0.3)	-0.31%
10-100kW	673.6	680.5	685.8	(5.3)	-0.77%
110-1000kva	937.3	939.9	941.1	(1.2)	-0.13%
Over 1000kva	467.4	483.3	475.6	7.7	1.62%
Street lighting	36.0	31.5	30.9	0.6	1.94%
Total energy sales	5,652.2	5,763.3	5,763.6	(0.3)	-0.01%

Actual 2013 revenue from rates was relatively consistent with test year with an overall increase in actual sales of $526,000 (0.09%) from the 2013 Test Year. There was a 0.01% decrease in GWh sold in 2013 compared to 2013 Test Year. The largest variance in revenue can be seen in the Over 1000kva class where actual revenues increased by $849,000 (2.35%), offset by a decrease in revenues in forfeited discounts category.

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.

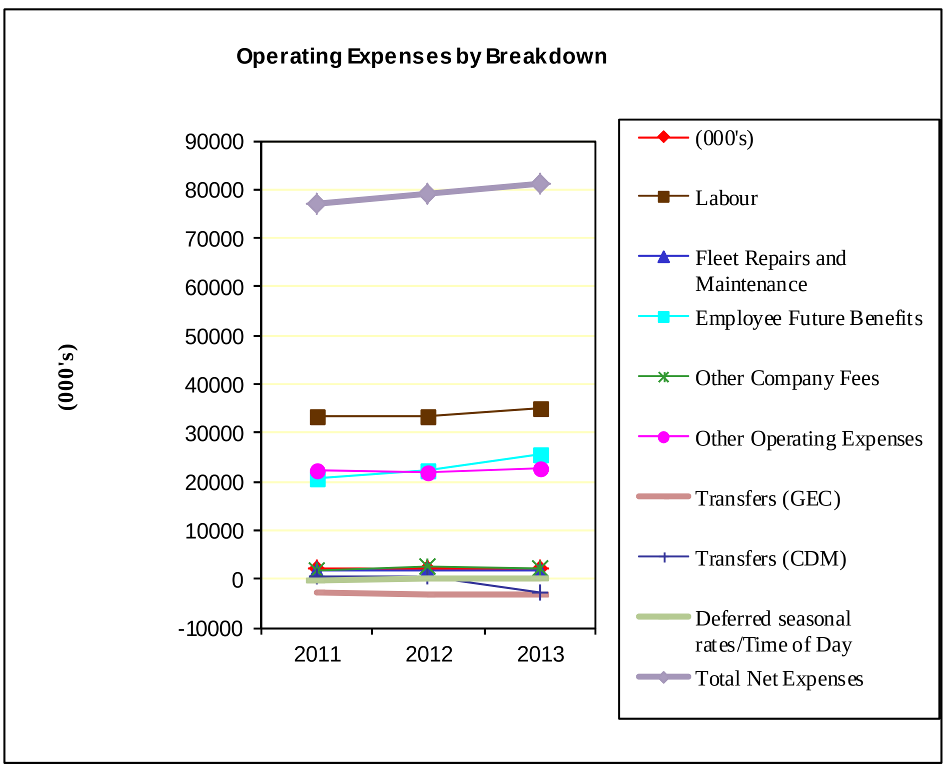
(000's)	Actual 2013	Test Year 2013	Actual 2012	Variance Actual -	Variance 2013 - 2012
Labour	$ 35,918	$ 34,955	$ 34,052	$ 963	$ 1,866
Reclass OPEB labour cost	(663)	(550)	(503)	(113)	(160)
Total Labour	35,255	34,405	33,549	850	1,706
Vehicle expense	1,881	1,860	1,827	21	54
Operating materials	1,568	1,687	1,577	(119)	(9)
Inter-company charges	1,184	1,358	1,259	(174)	(75)
Plants, Subs, System Oper & Bldgs	2,153	2,118	2,181	35	(28)
Travel	1,297	1,285	1,048	12	249
Tools and clothing allowance	1,141	1,115	1,109	26	32
Miscellaneous	1,751	1,636	1,624	115	127
Conservation	1,250	1,150	1,341	100	(91)
Taxes and assessments	1,011	1,016	988	(5)	23
Uncollectible bills	897	896	772	1	125
Insurance	1,197	1,191	1,188	6	9
Retirement allowance	84	100	114	(16)	(30)
Education, training, employee fees	392	395	285	(3)	107
Trustee and directors' fees	397	400	428	(3)	(31)
Other company fees	2,024	2,235	2,488	(211)	(464)
Stationery & copying	308	315	304	(7)	4
Equipment rental/maintenance	677	731	669	(54)	8
Communications	3,074	3,128	3,045	(54)	29
Advertising	1,113	1,485	1,029	(372)	84
Vegetation management	1,993	1,842	1,746	151	247
Computing equipment & software	799	805	828	(6)	(29)
Total other	26,191	26,748	25,850	(557)	341
Pension & early retirement program	14,744	12,189	12,896	2,555	1,848
OPEB's	10,880	10,461	9,274	419	1,606
Total employee future benefits	25,624	22,650	22,170	2,974	3,454
Total gross expenses	$ 87,070	$ 83,803	$ 81,569	$ 3,267	$ 5,501
Transfers (GEC)	(3,415)	(3,055)	(3,120)	(360)	(295)
CDM amortization	339	339	339	-	-
Deferred CDM program costs	(2,937)	(3,065)	-	128	(2,937)
Deferred seasonal rates/TOD	(71)	(140)	(84)	69	13
Deferred regulatory costs	322	417	253	(95)	69
Total net expenses	$ 81,308	$ 78,299	$ 78,957	$ 3,009	$ 2,351

The above table provides details of operating and general expenses by "breakdown" for 2012, Test Year 2013 and 2013 Actual.

Net operating expenses in 2013 increased by $2,351,000 from 2012 and by $3,009,000 in comparison to the 2013 test year. The increase is primarily due to an increase in labour, pension costs and OPEBs. These and other 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 2013 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 shows the trend in operating expenses by breakdown for the period 2011 to 2013.

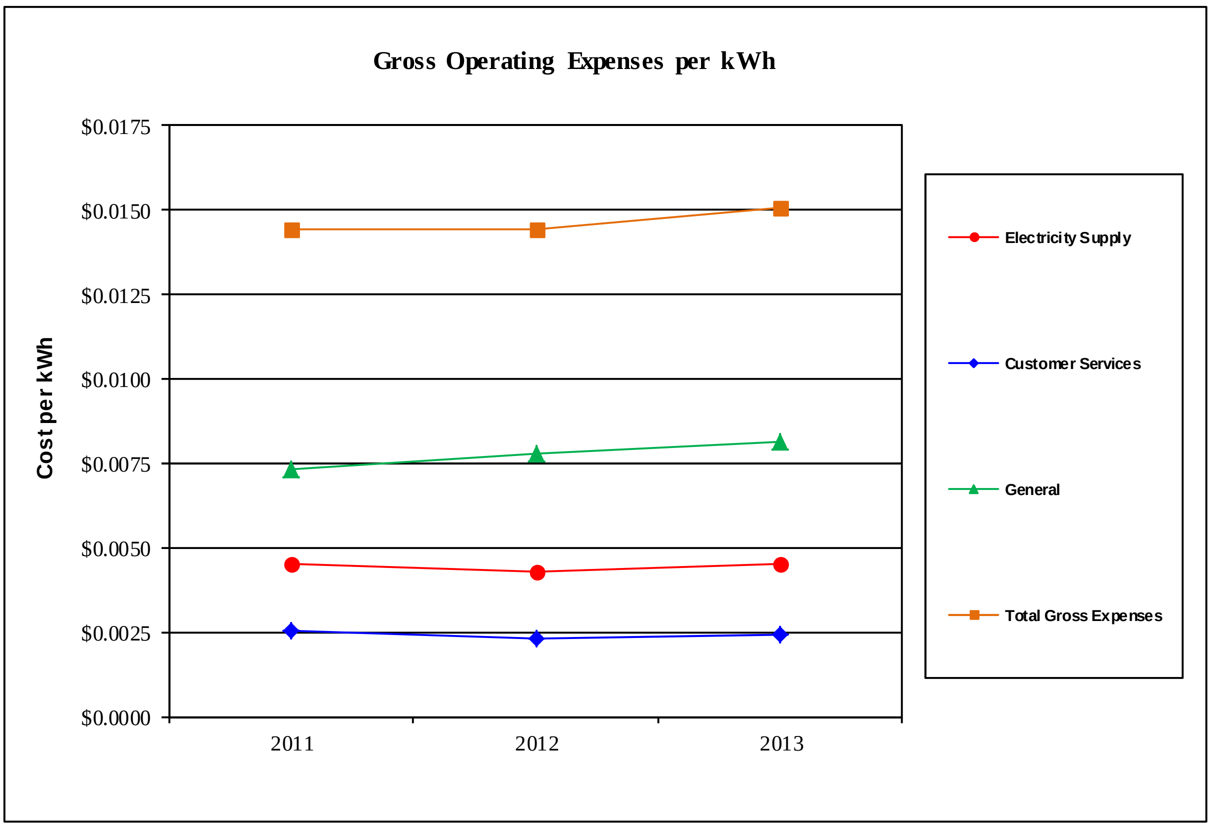
	Actual		
(000's)	**2011**	**2012**	**2013**
Labour	$ 33,351	$ 33,549	**$ 35,255**
Fleet Repairs and Maintenance	1,779	1,827	**1,881**
Employee Future Benefits	20,569	22,170	**25,624**
Other Company Fees	1,926	2,488	**2,024**
Other Operating Expenses	22,392	21,788	**22,608**
Transfers (GEC)	(2,914)	(3,120)	**(3,415)**
Transfers (CDM)	339	339	**(2,598)**
Deferred seasonal rates/Time of Day	(258)	(84)	**(71)**
Total Net Expenses	$ 77,184	$ 78,957	**$ 81,308**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2011 to 2013 is presented in the table below.

Comparison of Gross Operating Expenses to Total kWh Sold

		Electricity Supply		Customer Services		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
2011	5,552,800	$ 25,009	$0.0045	$ 14,253	$0.0026	$ 40,755	$0.0073	$ 80,017	$0.0144
2012	5,652,200	$ 24,420	$0.0043	$ 13,052	$0.0023	$ 44,097	$0.0078	$ 81,569	$0.0144
2013	5,763,300	$ 26,072	$0.0045	$ 14,009	$0.0024	$ 46,989	$0.0082	$ 87,070	$0.0151



The table and graph show that total gross expenses per kWh have increased by approximately 5% compared to 2012. This is largely due to an increase in pension costs and OPEBs included in General costs.

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 2011 to 2013 is as follows:

	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Actual - Test Year	Actual 2013-2012
Executive Group	**6.0**	**6.0**	6.7	7.0	-	(0.7)
Corporate Office	**21.0**	**21.2**	19.2	17.9	(0.2)	1.8
Finance	**89.1**	**83.2**	72.3	71.2	5.9	16.8
Engineering and Operations	**422.1**	**430.1**	439.1	413.3	(8.0)	(17.0)
Customer Relations	**62.0**	**65.1**	60.3	62.9	(3.1)	1.7
	600.2	**605.6**	597.6	572.3	(5.4)	2.6
Temporary employees	**55.6**	**48.2**	55.0	67.8	7.4	0.6
Total	**655.8**	**653.8**	652.6	640.1	2.0	3.2
Year over year percentage change	**0.49%**	**-**	1.95%	0.08%		

The overall number of FTE's in 2013 compared to 2012 increased by 3.2. The budgeted number of FTE's in the 2013 Test Year was 653.8 versus actual of 655.8. The variances between 2013, 2013 Test Year and 2012 are the result of the following:

- The Executive decreased compared to 2012 due to timing of retirements and an employee transfer from Finance in 2012.
- The Corporate Office is higher than 2012 due primarily to the addition of a Manager of Corporate Communications and a Human Resource Advisor during 2013.
- Finance is higher than 2012 due primarily to the transfer of all stores employees from Engineering & Operations. 2013 is higher than 2013 Test Year due primarily to the transfer of regional stores employees from Engineering & Operations, whereas only the transfer of central stores employees was included in the test year.
- Engineering and Operations is lower than 2012 and 2013 Test Year due primarily to the transfer of all stores employees to Finance.
- Customer Relations is higher than 2012 due primarily to the expansion of customer energy conservation programming in 2013. 2013 is lower than 2013 Test Year due primarily to timing of the approval of the expansion of customer energy conservation programming outlined in the 2013/2014 General Rate Application as well as a shift to temporary employees for replacement coverage of temporary assignments, retirements and leaves.
- Temporary Employees are consistent with 2012 but higher than 2013 Test Year due primarily to timing of temporary assignments, retirements and leaves as well as to support Information Technology.

An analysis of salaries and wages by type of labour and by function from 2011 to 2013, including 2013 test year is as follows:

(000's)	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual-Test	Variance 2013-2012
Type						
Internal labour	$ 59,784	$ 58,764	$ 57,280	$ 54,158	$ 1,020	$ 2,504
Overtime	5,228	4,719	5,326	5,758	509	(98)
	65,012	63,483	62,606	59,916	1,529	2,406
Contractors	13,613	8,668	11,192	9,743	4,945	2,421
	$ 78,625	$ 72,151	$ 73,798	$ 69,659	$ 6,474	$ 4,827
Function						
Operating	$ 35,918	$ 34,064	$ 34,052	$ 33,844	$ 1,854	$ 1,866
Capital and miscellaneous	42,707	38,087	39,746	35,815	4,620	2,961
Total	$ 78,625	$ 72,151	$ 73,798	$ 69,659	$ 6,474	$ 4,827
Year over year percentage change	6.54%		5.94%	15.88%		
Actual 2013 verses Test Year 2013		8.97%				

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 2013 were $4,827,000 (6.54%) higher than 2012.

Internal labour costs in 2013 were higher than 2012 by 4.37% primarily due to normal salary increases.

Contractors are used to supplement the Company's work force during peak periods of construction. The 21.63% increase in contract labour from 2012 was due primarily to increased distribution and transmission work associated with the Company's 2013 capital program to address customer growth.

Also, according to the table above, the 2013 total labour costs was $6,474,000 more than the 2013 test year, representing a 8.97% increase. According to the Company, the increase in 2013 operating labour over the 2013 test year is primarily due to higher overtime costs incurred in response to loss of supply issues, peak load management, increased trouble calls and inclement weather conditions. The increase in 2013 capital and miscellaneous labour over the 2013 test year is primarily due to increase distribution work resulting from higher customer growth than anticipated.

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 2011 to 2013, including 2013 test year are included in the table below:

(000's)	Salary Cost Per FTE					
	Actual 2013	**Test Year 2013**	Actual 2012	Actual 2011	Variance Actual-Test	Variance 2013-2012
Total reported internal labour costs	**$ 59,784**	**$ 59,655**	$ 57,280	$ 54,158	$ 129	$ 2,504
Benefit costs (net)	**(7,502)**	**(7,766)**	(7,074)	(6,909)	264	(428)
Other adjustments	**(506)**	**(508)**	(525)	(376) [1]	2	19
Base salary costs	**51,776**	**51,381**	49,681	46,873	395	2,095
Less: executive compensation	**(1,893)**	**(1,684)**	(1,806)	(1,690)	(209)	(87)
Base salary costs (excluding executive)	**$ 49,883**	**$ 49,697**	$ 47,875	$ 45,183	$ 186	$ 2,008
FTE's (including executive members)	**655.8**	**653.8**	652.6	640.1		
FTE's (excluding executive members)	**651.8**	**649.8**	648.6	636.1		
Average salary per FTE	**78,951**	**78,588**	76,128	73,228		
% increase	**3.71%**		3.96%	4.41%		
% increase "Actual 2013" vs Test Year	**0.46%**					
Average salary per FTE (excluding executive members)	**76,531**	**76,480**	73,813	71,031		
% increase	**3.68%**		3.92%	4.25%		
% increase "Actual 2013" vs Test Year	**0.07%**					

[1] 2011 adjustments were restated in 2012. 2011 was previously stated as 261 working days and was revised in 2012 to 260 working days.

The above analysis indicates that for 2013 the rate of increase in average salary per FTE has been fairly consistent from 2011 to 2013.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2011 to 2013 and the targets set for 2013:

Measure	**Target 2013**	**Actual 2013**	**Actual 2012**	**Actual 2011**
Controllable Operating Costs/Customer	**$220.2**	$217.6	$222.2	$214.2
Earnings	**35.3m**	36.5m	34.2m	33.7m
Reliability - Duration of Outages (SAIDI)	**2.53**	2.23	2.44	2.57
Customer Satisfaction - % Satisfied	**87.6%**	85.9%	86.7%	88.5%
Customer Satisfaction - 1st Call Resolution	**-**	-	88.7%	88.5%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	**1.05**	0.52	1.74	1.8
Regulatory Performance	**Subjective**	150%	-	-

The 2013 STI results were adjusted to remove the impact of severe weather conditions and energy supply issues in January and November. Also in 2013, First Call Resolution was replaced with Regulatory Performance. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or cost based analyses. For 2013, the key determinants of the result of 150% were the efficient management of (i) the 2013/2014 general rate application, including the public hearing process,

(ii) the 2014 capital budget application, (iii) the $14.5 million Bell Island Cable Replacement supplemental capital application, and (iv) the multiple Newfoundland & Labrador Hydro applications filed in 2013.

The Company's STI program also includes an individual performance measure for Executives and Managers. 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%
Other Executives	50%	50%
Managers	50%	50%

The individual measures of performance for Managers 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 2013 is established as a percentage of base pay for the three employee groups. For 2013, measures relating to 'controllable operating costs/customer', 'earnings', 'SAIDI', 'safety' and 'regulatory performance' metrics were met, however the 'customer satisfaction - % satisfied' metric fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2011 to 2013:

STI Payout

	Target 2013	**Actual 2013**	**Target 2012**	**Actual 2012**	**Target 2011**	**Actual 2011**
President	**50%**	**70.0%**	**50%**	**70.0%**	**50%**	**63.6%**
Executive	**35-40%**	**52.1%**	**35-40%**	**51.1%**	**35-40%**	**48.2%**
Managers	**15%**	**21.2%**	**15%**	**20.2%**	**15%**	**16.9%**

STI actual payout rates for 'executive' and 'manager' employee groups are higher than in the prior year, while they have remained the same for the President.

In dollar terms, the STI payouts for 2011 to 2013 are as follows:

	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
President	**$ 294,000**	$ 280,000	$ 245,000	$ 14,000
Executive	**404,000**	381,000	345,000	23,000
Managers	**302,000**	271,000	245,200	31,000
Total	**$1,000,000**	$ 932,000	$ 835,200	$ 68,000
Year over year percentage change	**7.30%**	11.59%	18.17%	

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In 2013, the non-regulated portion (before tax adjustment) was $285,225 (2012 - $170,200).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2011 to 2013.

	Base Salary	Short Term Incentive	Other	Total
2013				
Total executive group	$ 1,195,019	$ 698,000	$ 126,744	$ 2,019,763
Average per executive (4)	**$ 298,755**	**$ 174,500**	**$ 31,686**	**$ 504,941**
2012				
Total executive group	$ 1,145,021	$ 661,000	$ 129,201	$ 1,935,222
Average per executive (4)	**$ 286,255**	**$ 165,250**	**$ 32,300**	**$ 483,806**
2011				
Total executive group	$ 1,100,319	$ 590,000	$ 127,325	$ 1,817,644
Average per executive (4)	**$ 275,080**	**$ 147,500**	**$ 31,831**	**$ 454,411**
% Average increase 2013 vs 2012	**4.37%**	**5.60%**	**(1.90%)**	

Base salary for the executive group increased from 2012 due to salary increases approved by the Board of Directors. Base salaries have been agreed to the 2013 Board of Directors' minutes, and STI payouts have been agreed to the 2014 Board of Directors' minutes.

Company Pension Plan

For 2013, we reviewed the accounts supporting the gross charge of $14,744,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2011 to 2013, including the 2013 test year is as follows:

	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual-Test	Variance 2013-2012
Pension expense per actuary	**$ 12,744,000**	**$ 10,405,000**	$ 11,153,000	$ 10,056,965	$ 2,339,000	$ 1,591,000
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**560,000**	**496,000**	484,934	444,163	64,000	75,066
Group RRSP @ 1.5%	**440,000**	**494,000**	459,000	467,000	(54,000)	(19,000)
Individual RRSP's	**1,013,000**	**844,000**	813,000	616,000	169,000	200,000
Less: Refunds (net of other expenses)	**(13,000)**	**(50,000)**	(14,000)	(18,128)	37,000	1,000
Total	**$ 14,744,000**	**$ 12,189,000**	$ 12,895,934	$ 11,566,000	$ 2,555,000	$ 1,848,066
Year over year percentage change	14.33%		11.50%	52.42%		
% increase Actual 2013 vs Test Year		20.96%				

Overall, pension expense for 2013 is higher than 2012 primarily due to a lower discount rate at December 31, 2012 (4.40% compared to 5.00%), which is used to determine the pension obligation for 2013, as well as a lower service life of active members. The pension expense for 2013 is higher than test year 2013 primarily due to an increase in amortization from an actuarial loss of $38.4 million booked at 2012 year-end. The loss was largely due to a decrease in interest rate from the initial projection of 4.90% to the year-end 2012 actual rate of 4.40%.

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 P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses increased by 15.48% in 2013.

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. The increase of approximately $181,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2012 was primarily the result of wage increases and new hires in the year. This was partially offset by retirements and terminations.

Retirement Allowance

The retirement allowance costs incurred by the Company over the period from 2011 to 2013, including 2013 test year are as follows:

(000's)	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual-Test	Variance 2013-2012
Terminations and Severance	$ 68	$ 90	$ 100	$ 154	$ (22)	$ (32)
Other Retiring Allowance Costs	16	10	14	10	6	2
Total	$ 84	$ 100	$ 114	$ 164	$ (16)	$ (30)
Year over year percentage change	-26.32%		-30.49%	-76.97%		

There were 26 retirements in 2013, compared to 27 retirements in 2012.

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 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 2011 to 2013, including the 2013 test year is as follows:

(000s)	2013 Actual	2013 Test Year	2012 Actual	2011 Actual
Accrued OPEBs	$ 7,957	$ 7,419	$ 6,212	$ 5,895
Amortization of transitional balance	3,504	3,504	3,504	3,504
Amount capitalized	(581)	(462)	(442)	(396)
	$ 10,880	$ 10,461	$ 9,274	$ 9,003

Consistent with the explanation provided above for pension costs, OPEB costs were higher in 2013 due to a lower discount rate at December 31, 2012, which is used to determine the Company's OPEBs obligation.

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) and P.U. 43 (2009);
- compared intercompany charges for the years 2011 to 2013 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2013 and investigated any unusual items;
- vouched a sample of transactions for 2013 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 2011 to 2013 for charges to and from Newfoundland Power Inc.:

	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges from related companies				
Regulated	**$ 203,300**	$ 202,524	$ 130,719	$ 776
Non-Regulated	**1,467,175**	1,575,092	1,602,265	(107,917)
Total	**$ 1,670,475**	$ 1,777,616	$ 1,732,984	$ (107,141)
Charges to related companies	**$ 506,639**	$ 659,162	$ 913,593	$ (152,523)

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 2013.

- Fortis Inc. estimated its net pool of operating expenses for 2013 in Q4 2012 as part of its annual business planning process 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 evenly based upon 25% of the estimated annual amount.
- Fortis Inc. used actual year-to-date expenditures up to October and estimated November and December's expenses for the determination of its actual "true up" calculation. Fortis also used actual assets at September 30, 2013 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of November and December's expenditures had a minimal impact.

During the fourth quarter of 2013, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $1,184,000 and are summarized as follows:

2013 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$558,000	Non-regulated
Director Fees	136,000	Non-regulated
Consulting and Legal fees	112,000	Non-regulated
Trustee Agent Fees	53,000	Regulated
Audit and Other Fees	39,000	Non-regulated
Public Reporting Costs	51,000	Non-regulated
Annual Meeting Expenses	41,000	Non-regulated
Travel (Board and Other)	49,000	Non-regulated
Insurance (D&O)	42,000	Non-regulated
Other Costs	103,000	Non-regulated
	1,184,000	
Less amounts previously billed:		
Q1 2013	310,000	
Q2 2013	310,000	
Q3 2013	306,000	
Q4 2013 balance owing	$ 258,000	

For 2013, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 8.85%, down from 9.72% in 2012.

As detailed above, trustee agent fees for $53,000 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 2011 to 2013 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 53,000**	$ 52,000	$ 51,000	$ 1,000
Miscellaneous	**14,185**	13,362	7,629	823
Non-Joint Use Poles	**-**	-	11,566	-
	$ 67,185	$ 65,362	$ 70,195	$ 1,823
Year over year percentage change	**2.79%**	-6.89%	-1.13%	
Charges to Fortis Inc.				
Postage and couriers	**$ 24,565**	$ 24,457	$ 22,263	$ 108
Staff charges	**97,979**	201,332	299,786	(103,353)
Staff charges - insurance	**183,267**	203,524	179,005	(20,257)
IS Charges	**309**	-	-	309
Pole removal and installation	**572**	3,606	20,191	(3,034)
Miscellaneous	**6,090**	13,367	92,974	(7,277)
	$ 312,782	$ 446,286	$ 614,219	$ (133,504)
Year over year percentage change	**-29.91%**	-27.34%	-19.99%	

The most significant fluctuation from our analysis of regulated intercompany charges is a $103,353 decrease in staff charges charged to Fortis Inc. Charges in 2012 related to Newfoundland Power staff involvement in the acquisition of Central Hudson Gas & Electric by Fortis Inc. With the successful closure of this acquisition in early 2013, the involvement by Newfoundland Power staff was significantly reduced from the previous year.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2011 to 2013:

(Non-Regulated)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges from Fortis Inc.				
Director's fees and travel	**$ 185,000**	$ 219,000	$ 200,000	$ (34,000)
Annual and quarterly reports	**90,000**	96,000	117,000	(6,000)
Staff charges	**558,000**	557,000	574,000	1,000
Miscellaneous	**634,175**	697,130	711,265	(62,955)
	$ 1,467,175	$ 1,569,130	$ 1,602,265	$ (101,955)
Year over year percentage change	**(6.50%)**	(2.07%)	14.29%	

The total non-regulated charges from Fortis Inc. have decreased by 6.50% ($101,955) from 2012.

The following table provides a summary and comparison of the other intercompany transactions for 2011 to 2013:

Intercompany Transactions (Other)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges to Fortis Properties				
Staff charges	**$ -**	$ 864	**$** -	$ (864)
Staff charges - insurance	**30,894**	33,089	37,042	(2,195)
Stationary costs	**352**	529	678	(177)
Miscellaneous	**2,770**	3,134	2,147	(364)
	$ 34,016	$ 37,616	$ 39,867	$ (3,600)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 52,961**	$ 58,212	$ 37,387	$ (5,251)
Miscellaneous	**1,636**	8,944	8,029	(7,308)
	$ 54,597	$ 67,156	$ 45,416	$ (12,559)
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 4,091**	$ 3,697	$ 1,622	$ 394
Staff charges	**16,587**	10,658	7,065	5,929
IS charges	**4,080**	6,224	3,351	(2,144)
Miscellaneous	**370**	350	360	20
	$ 25,128	$ 20,929	$ 12,398	$ 4,199
Charges to Maritime Electric				
Staff charges	**$ 6,976**	$ 6,418	$ 16,296	$ 558
Staff charges - insurance	**1,954**	10,005	2,693	(8,051)
IS charges	**2,856**	1,915	4,787	941
Miscellaneous	**573**	540	550	33
	$ 12,359	$ 18,878	$ 24,326	$ (6,519)
Charges from Maritime Electric				
Staff charges	**$ -**	$ 33,932	$ -	$ (33,932)
Miscellaneous	**5,614**	5,999	9,211	$ (385)
	$ 5,614	$ 39,931	$ 9,211	$ (34,317)
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 4,647**	$ -	$ -	$ 4,647
Charges to Central Hudson Gas & Electric				
Staff charges - insurance	**$ 6,702**	$ -	$ -	$ 6,702
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	**$ 6,177**	$ -	$ 432	$ 6,177
	$ 6,177	$ -	$ 432	$ 6,177
Charges to Fortis US Energy Corp				
Staff charges - insurance	**$ 74**	$ 1,176	$ 2,581	$ (1,102)

Intercompany Transactions (Other) Cont'd.		Actual 2013		Actual 2012		Actual 2011		Variance 2013-2012
Charges to Belize Electricity								
Staff charges	$	-	$	-	$	-	$	-
Staff charges - insurance				-		1,296		-
Miscellaneous		-		-		1,176		-
	$	-	$	-	$	2,472	$	-
Charges to Fortis Alberta Inc.								
Staff charges	$	-	$	-	$	18,219	$	-
Staff charges - insurance		**3,359**		341		3,365		3,018
Miscellaneous		**3,650**		3,270		3,120		380
	$	**7,009**	$	3,611	$	24,704	$	3,398
Charges from Fortis Alberta Inc.								
Staff charges	$	-	$	-	$	4,805	$	-
Miscellaneous		**41,411**		30,637		-		10,774
	$	**41,411**	$	30,637	$	4,805	$	10,774
Charges to Fortis BC Inc.								
Staff charges	$	-	$	16,023	$	-	$	(16,023)
IS charges		**11,424**		13,405		13,405		(1,981)
Staff charges - insurance		**2,768**		715		5,869		2,053
Miscellaneous		**2,363**		2,330		1,944		33
	$	**16,555**	$	32,473	$	21,218	$	(15,918)
Charges from Fortis BC Inc.								
Miscellaneous	$	**8,740**	$	-	$	1,092	$	8,740
Charges to Fortis BC Holdings								
Staff charges	$	-	$	-	$	10,215	$	-
Staff charges - insurance		**2,882**		324		2,983		2,558
Miscellaneous		**6,290**		6,500		6,547		(210)
	$	**9,172**	$	6,824	$	19,745	$	2,348
Charges to Caribbean Utilities Co. Limited								
Staff charges	$	**54,492**	$	67,524	$	6,938	$	(13,032)
Staff charges - insurance		**11,048**		162		21,168		10,886
Miscellaneous		**1,400**		281		-		1,119
	$	**66,940**	$	67,967	$	28,106	$	(1,027)
Charges from Caribbean Utilities Co. Limited								
Miscellaneous	$	**21,106**	$	5,400	$	-	$	15,706

Intercompany Transactions (Other) Cont'd.	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges to Fortis Turks and Caicos				
Staff Charges	$ -	$ 6,638	$ 117,504	$ (6,638)
Staff Charges - insurnce	9,477	16,764	5,946	(7,287)
Miscellaneous	248	-	75	248
	$ 9,725	$ 23,402	$ 123,525	$ (13,677)

The most significant fluctuations from our analysis of other intercompany charges for 2013 compared to 2012 are as follows:

- Staff charges from Maritime Electric decreased by $33,932 from 2012. The 2012 charges related to Maritime Electric staff working on restoration of power in the aftermath of Tropical Storm Leslie.
- Staff charges to FortisBC Inc. decreased by $16,023 from 2012. The 2012 charges related to engineering services provided for a proposed hydroelectric generating project being considered by a subsidiary of FortisBC Inc.

On three occasions during the year the Company entered into short term loan agreements with related parties. These loans are as follows:

Lender	Amount Borrowed	Date Borrowed	Date Repaid	Interest Rate	Total Interest Cost
Maritime Electric Ltd	$ 15,000,000	April 22, 2013	June 27, 2013	1.57%	$ 42,584
Maritime Electric Ltd	$ 10,000,000	July 22, 2013	Sept 20, 2013	1.60%	$ 26,301
Maritime Electric Ltd	$ 8,000,000	Sept 20, 2013	Nov 7, 2013	1.56%	$ 16,412
	$ 33,000,000				$ 85,297

In Order 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 2013. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2013.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2013/14 General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2013 and noted some exceptions. Only staff charges relating to the Director of Risk Management are charged at $108 per hour, whereas staff charges relating to routine insurance matters (e.g.; coverage queries, damage claims, arranging for insurance certificates) are based on the recovery of fully distributed costs (hourly rate plus 71% markup). These charges were further investigated to determine the impact of using a lower rate. It was determined that had the Company charged $108 per hour rather than the fully distributed cost, an additional $17,500 in staff insurance charges to related parties would result. The Company indicated that this is in accordance with Section 6.5 – Shared Corporate Services of the Newfoundland Power Inc. Inter-Affiliate Code of Conduct (May 2011) submitted to the Board on June 10, 2011.

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 2013 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Other company fees				
Other company fees	$ 1,648	$ 1,389	$ 1,748	$ 259
Regulatory hearing costs - other	376	1,099	178	(723)
	$ 2,024	$ 2,488	$ 1,926	$ (464)
Year over year percentage change	-18.6%	29.2%	13.8%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 322	$ 253	$ 253	$ 69
Year over year percentage change	27.3%	0.0%	-44.2%	

Total company fee costs for 2013 were lower than 2012 actual by $464,000 primarily due to reduced consultants work required for regulatory activity partially offset by increases in consultant costs required for expansion of customer energy conservation programming. 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 2011 to 2013 is as follows:

(000's)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Miscellaneous	**$ 1,048**	$ 857	$ 858	$ 191
Cafeteria and lunchroom supplies	**95**	93	97	2
Promotional items	**119**	101	118	18
Computer software	**5**	34	3	(29)
Damage claims	**241**	215	141	26
Community relations activities	**11**	3	3	8
Donations and charitable advertising	**172**	221	180	(49)
Books, magazines and subscriptions	**33**	67	45	(34)
Misc. lease payments	**27**	33	23	(6)
Total miscellaneous expenses	**$ 1,751**	$ 1,624	$ 1,468	$ 127
Year over year percentage change	**7.83%**	10.63%	(13.80%)	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2012 to 2013 these expenses have increased by 7.83% overall, primarily due to the expansion of customer energy conservation programming.

Donations and charitable advertising included in miscellaneous expenses are non-regulated expenses.

Our procedures in this expense category for 2013 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 2013 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2013 Conservation and Demand Management Report with the Board. This report provided a summary of 2013 CDM activities and costs as well as the outlook for 2013.

In 2013, the Company offered four residential customer energy conservation programs. Those customer energy conservation programs for (i) Energy Star windows, (ii) insulation, (iii) high performance thermostats, and (iv) heat recovery ventilators ("HRV's") are bundled together for marketing purposes as the takeCharge Energy Savers. The primary objective of these programs are to reduce space heating energy consumption and provide reductions in peak demand.

Costs in 2013 totaled $3,929,000 compared to $3,397,000 in 2012, a $532,000 increase over 2012. The increase that was experienced in 2013 is primarily due to spending in the Conservation Program category – specifically in the Energy Saver program (Windows). This category experienced a $409,000 increase over 2012 costs. In 2013, $2,937,000 ($2,085,000 after tax) in CDM costs were deferred with annual amortization in the amount of $298,000 to commence in 2014.

Going forward, the Company plans to increase program participation among customers retrofitting existing homes, launch a new residential conservation program, and conduct research to enhance its planning activities.

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 2013 and 2012, including test year 2013, as follows:

(000's)	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual - Test	Variance 2013-2012
Vehicle expense	**1,881**	**1,860**	**1,827**	1,779	21	54
Operating materials	**1,568**	**1,687**	**1,577**	1,533	(119)	(9)
Plants, Subs, System Oper & Bldgs	**2,153**	**2,118**	**2,181**	1,993	35	(28)
Travel	**1,297**	**1,285**	**1,048**	1,282	12	249
Tools and clothing allowance	**1,141**	**1,115**	**1,109**	1,031	26	32
Conservation	**1,250**	**1,150**	**1,341**	2,184	100	(91)
Taxes and assessments	**1,011**	**1,016**	**988**	895	(5)	23
Uncollectible bills	**897**	**896**	**772**	1,204	1	125
Insurance	**1,197**	**1,191**	**1,188**	1,082	6	9
Education, training, employee fees	**392**	**395**	**285**	318	(3)	107
Trustee and directors' fees	**397**	**400**	**428**	399	(3)	(31)
Stationery & copying	**308**	**315**	**304**	302	(7)	4
Equipment rental/maintenance	**677**	**731**	**669**	629	(54)	8
Communications	**3,074**	**3,128**	**3,045**	3,086	(54)	29
Advertising	**1,113**	**1,485**	**1,029**	906	(372)	84
Vegetation management	**1,993**	**1,842**	**1,746**	1,612	151	247
Computing equipment & software	**799**	**805**	**828**	774	(6)	(29)
Transfers (GEC)	**(3,415)**	**(3,055)**	**(3,120)**	(2,914)	(360)	(295)
Transfers (CDM)	**339**	**339**	**339**	339	-	-
Deferred seasonal rates/Time of Day	**(71)**	**(140)**	**(84)**	(258)	69	13

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

- Operating materials were lower than test year primarily due to less operating materials being required for distribution and substation maintenance work encountered.
- Travel costs increased by $249,000 due to higher employee relocation costs.
- Uncollectible bills increased by $125,000 primarily due to 2012 including a reversal of a provision for potentially uncollectible amounts related to the Bell Aliant joint-use pole sale. In addition, uncollectible bills vary from year to year as a result of general economic conditions.
- Conservation was higher than test year primarily due to higher customer participation in energy conservation rebate programs leading to increased incentives.
- Education, training and employee fees increased by $107,000 primarily due to increased training requirements for customer service and mobile technology.
- Advertising costs is lower than test year by $372,000 primarily due to timing of the approval of the expansion of customer energy programming outlined in the 2013/14 General Rate Application.
- Vegetation management costs increased over 2012 and test year primarily due to increased vegetation management activity for distribution and plant operations.
- GEC transfers increased over 2012 and test year primarily due to higher pension 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.***

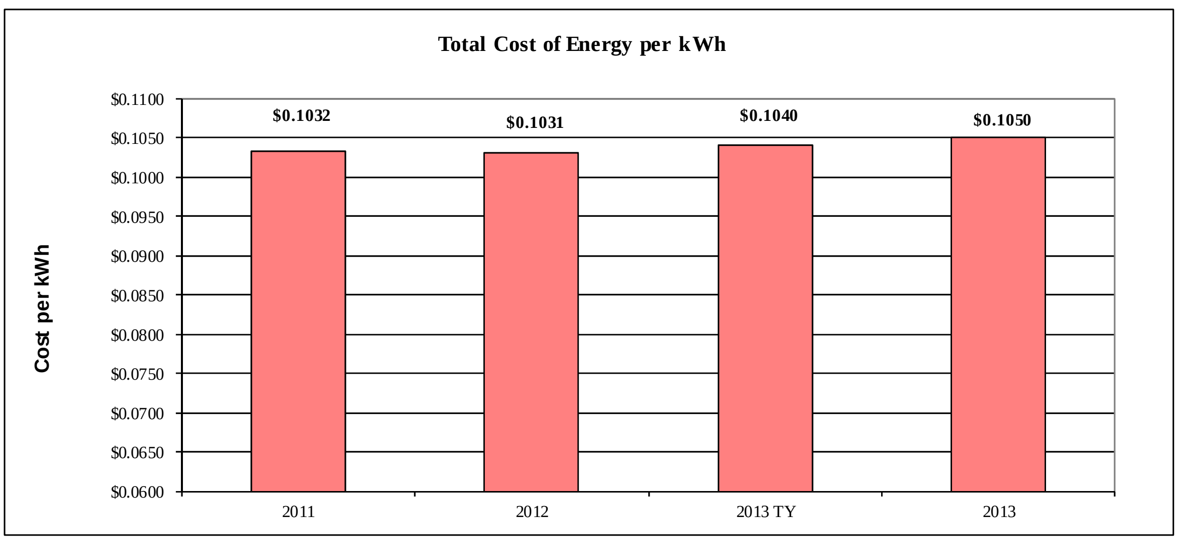
The following table and graph provide the total cost of energy (expressed in kWh) from 2011 to 2013, including 2013 test year (includes non-regulated):

(000's)

Year	kWh sold	Operating Expenses	Purchased Power	Deferred Cost recoveries and amortizations	Depreciation	Finance Charges*	Income Taxes	Net Earnings	Total Cost of Energy	Cost per kWh
2011	5,552,800	$ 77,184	$ 369,484	$ (2,363)	$ 42,695	$ 35,944	$ 17,661 [1]	$ 32,467 [1]	$ 573,072	$ 0.1032
2012	5,652,200	$ 78,957	$ 380,374	$ (4,850)	$ 47,372 [2]	$ 35,856	$ 8,007 [2]	$ 37,204	$ 582,920	$ 0.1031
2013 TY	5,763,600	$ 78,299	$ 389,103	$ (768)	$ 46,647	$ 35,487	$ 14,702	$ 35,906	$ 599,376	$ 0.1040
2013	5,763,300	$ 81,308	$ 390,210	$ (768)	$ 51,300	$ 36,034	$ (2,877)	$ 49,920	$ 605,127	$ 0.1050

1 - Restated as a result of the Company's adoption of U.S. GAAP

2 - There was a reclass related to income tax and depreciation in 2012 of $2,854,000



Purchased Power

We have reviewed the Company's purchased power expense for 2013 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 $9.8 million, from $380.4 million in 2012 to $390.2 million in 2013. According to the Company, the increase resulted from (i) electricity sales growth; (ii) lower generation than water inflows at the Company's hydroelectric generating facilities; and, (iii) the amortization of the 2011 balance of the Weather Normalization Account.

Purchased power expense for 2013 test year is $389.1 million compared to $390.2 million in 2013, which represents an increase of $1.1 million or a 0.3% increase.

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, 2010 and assessed the reasonableness of depreciation expense.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. The study for plant in service as of December 31, 2010 was completed in 2011. The study was included in the 2013-2014 General Rate Application by the Company and was approved in P.U. 13 (2013), including the approval of the accumulated depreciation reserve variance of $2.6 million to be amortized over the average remaining service life of the related assets. The new depreciation rates from the 2010 depreciation study, including the amortization of the accumulated depreciation reserve, were implemented effective January 1, 2013.

Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method in its 2010 depreciation study as this method provides for a better match of depreciation expense and loss in service. The next study for plant in service is to be completed as of December 31, 2014 and included in the 2015-2016 General Rate Application.

The objective of our procedures in this section was to ensure that the 2013 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2010 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 2013; and,
- assessed the overall reasonableness of the depreciation for 2013.

Amortization expense for 2013 is $51,300,000 as compared to $47,372,000 for 2012, representing an 8.29% increase. The 2013 and 2012 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:

('000s)	**2013**	**2012**	**Variance 2013-2012**	**%**
Depreciation and amortization as reported	$ 51,300	$ 47,372	$ 3,928	8.29%
Less: Tax on Cost of Removal [1]	(4,336)	(2,854)	(1,482)	51.93%
Depreciation of Fixed Assets	$ 46,964	$ 44,518	$ 2,446	5.49%

Note 1: Recognised as income tax for financial reporting purposes.

The change to 2012 depreciation was a change in presentation only and had no impact on net earnings.

The following table provides a comparison of the depreciation of fixed assets for 2013, 2013 test year and 2012:

('000s)	**2013**	**2013 TY**	**2012**	**Variance 2013-2013TY**	**Variance 2013-2012**
Depreciation of Fixed Assets	$ 46,964	$ 46,647	$ 44,518	$ 317	$ 2,446

Depreciation of fixed assets for 2013 is $46,964,000 as compared to $44,518,000 for 2012, representing a 5.49% increase. The change is attributable to the implementation of new rates approved in P.U. 13 (2013) and an increase of depreciable assets by approximately $61,907,000. The variance of depreciation of fixed assets for 2013 as compared to 2013 test year was $317,000, representing a 0.7% increase.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006), P.U. 32 (2007) and P.U. 13 (2013), as well as the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2010 have been incorporated into the Company's depreciation calculations for 2013.

Interest and 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:

(000's)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Interest				
Long-term debt	**$ 35,123**	$ 35,039	$ 35,444	$ 84
Other	**1,092**	921	702	171
Amortization				
Debt discount	**302**	337	308	(35)
Interest charged to construction	**(483)**	(441)	(510)	(42)
Total finance charges	**$ 36,034**	$ 35,856	$ 35,944	$ 178
Year over year percentage change	**0.50%**	-0.24%	-0.26%	

In the above table, the increase in interest on long term debt compared to 2012 is attributable to the increasing amount of bonds outstanding associated with the $70 million first mortgage sinking bond issue in 2013. The increase in other interest is due to higher borrowings under the Company's credit facility during the year. The test year 2013 interest and finance charges was $35,931,000 for financial reporting purposes (or $35,487,000 including the equity component of interest charged to construction). The variance of interest and finance charges for 2013 as compared to 2013 test year for financial reporting purposes was $103,000, representing a 0.03% increase.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2013 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2013 and have noted that the effective income tax rate decreased from 17.7% in 2012 to -6.1% in 2013. This decrease is primarily due to the allocation of the Part VI.1 tax liability and related Part 1 tax deduction from Fortis to the Company in 2013. Excluding the impact of the Part V1.1 tax for 2013, 20113 test year and 2012 results in the following effective rates:

('000s)	Actual 2013	Test Year 2013	Actual 2012	Variance 2013-2013 TY	Variance 2013-2012
Income tax expense *	$ (2,877)	$ 14,702	$ 8,007	$ (17,579)	$ (10,884)
Add back: Part VI.1 tax	12,814	-	2,589	12,814	10,225
	$ 9,937	$ 14,702	$ 10,596	$ (4,765)	$ (659)
Earnings before income taxes	$ 47,043	$ 50,608	$ 45,211	(3,565)	1,832
Effective income tax rate excluding Part V1.tax	21.1%	29.1%	23.4%	-7.9%	-2.3%

* The 2012 income tax expense was reclassifed in 2013 by $2,854,000 for the impact of the income tax deduction associated with the cost of removal of the Company's property, plant and equipment.

With the exclusion of the Part VI.1 tax, the effective rate decreased by 2.3% in 2013 compared to 2012 and decreased by 7.9% in 2013 compared to 2013 test year. The decrease for both 2013 actual to 2012 actual and 2013 actual to 2013 test year is primarily resulting from increased depreciation expense associated with the future cost of removal of the Company's property, plant and equipment recorded in depreciation expense. There was no change in the statutory tax rate for 2012, 2013 test year and 2013 which remained at 29%.

Upon adoption of U.S. GAAP in 2012, the Company was required to recognize the impact of the difference between enacted tax rates and substantially enacted tax rates related to the allocation of the unregulated Part VI.1 tax deduction from Fortis to Newfoundland Power. This resulted in the Company recording a $12.8 million income tax recovery.

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 2013 is unreasonable.

Costs Associated with Curtailable Rates

In 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 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 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.

Twenty–one customers participated in the Option during the 2012-2013 winter season. The total of the curtailment credits for 2013 was $222,074 compared to the 2012 credits of $332,754. Total operating costs incurred by the Company in 2013 were $243,392 compared to $357,152. The curtailment credit total for the 2012-2013 winter season is lower than the previous season's total primarily due to a higher number of curtailment failures this past winter season. There were 17 curtailment failures during this winter season. This is up significantly from last year. More than half of the curtailment failures resulted from customer's standby generation being unavailable when requested.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and 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 2013 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2013 and investigated any unusual items;
* 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 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charged from Fortis Companies:				
Annual report	**$ 90,000**	$ 96,000	$ 117,000	$ (6,000)
Directors' fees and travel	**185,000**	219,000	200,000	(34,000)
Hotel/Banquet Facilities	**-**	5,700	-	(5,700)
Staff charges	**558,000**	557,000	574,000	1,000
Miscellaneous	**634,200**	697,400	711,300	(63,200)
	1,467,200	1,575,100	1,602,300	(107,900)
Performance Share Unit Plan 1	**65,000**	-	-	65,000
Donations and charitable advertising	**221,200**	286,800	266,300	(65,600)
Executive short term incentive	**257,000**	170,200	26,400	86,800
Miscellaneous	**32,400**	79,700	94,100	(47,300)
	2,042,800	2,111,800	1,989,100	(69,000)
Less: Income taxes	**592,400**	612,400	606,700	(20,000)
Less: Part VI.1 tax adjustment	**12,814,000**	2,589,000	(221,300)	10,225,000
Total non-regulated (net of tax)	**$ (11,363,600)**	$ (1,089,600)	$ 1,603,700	$ (10,274,000)

1 The Performance Share Unit (PSU) was introduced in 2013, and the full expense associated with the Plan has been designated as non-regulated. The expense associated with the PSU Plan is not billed to Newfoundland Power by Fortis, which is why it was not included in the Intercompany Transactions Report.

In the table above the most significant fluctuation between 2013 and 2012 pertains to the Part VI.1 tax adjustment. This tax adjustment results from the payment by Fortis of dividends on its preferred shares. The Company has noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.’s corporate tax planning and preferred share dividend payment, and the Company’s capacity to cover this tax.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2013 this represents an addition to non-regulated expenses (before tax adjustment) of $257,000 (2012 - $170,200). 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 29.0% which agrees with the Company's statutory rate as identified in the 2013 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 2012 and 2013:

(000's)	2013 Actual	2012 Actual	Variance 2013-2012
Regulatory Assets			
Rate stabilization account	**$ 12,407**	$ 19,529	$ (7,122)
OPEBs asset	**42,048**	45,552	(3,504)
Pension deferral	**1,409**	2,537	(1,128)
Cost recovery deferral	**3,150**	4,726	(1,576)
Cost of capital cost recovery deferral	**1,658**	2,487	(829)
Revenue shortfall deferral	**3,172**	-	3,172
Deferred GRA costs	**644**	-	644
Conservation and demand management deferral	**2,937**	339	2,598
Optional seasonal rate revenue and cost recovery account	**134**	130	4
Employee future benefits	**133,096**	175,056	(41,960)
Demand management incentive account	**383**	-	383
Deferred income taxes	**171,212**	166,817	4,395
	$ 372,250	$ 417,173	$ (44,923)
Regulatory Liabilities			
Weather normalization account	**$ 7,081**	$ 6,549	$ 532
Future removal and site restoration provision	**130,693**	126,329	4,364
Demand management incentive account	**-**	785	(785)
Excess earnings	**68**	-	68
	$ 137,842	$ 133,663	$ 4,179

<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, 2013 were approved by the Board in P.U. 23 (2013). The RSA regulatory asset of $12,407,000 represents a current portion of $7,136,000 and a non-current portion of $5,271,000.

As of December 31, 2013, there was a charge to the RSA of $7,836,600 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007) and P.U. 43 (2009).

Pursuant to 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, 2013, the credit balance of $452,200 in the OPEBVDA account was credited to the RSA in accordance with P.U. 16 (2013).

Pursuant to 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, 2013, the balance of $2,081,909 in the PEVDA account was credited to the RSA in accordance with P.U. 16 (2013).

Pursuant to 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, 2013 $127,402 was credited to the RSA in accordance with P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account and the Optional Seasonal Rate Revenue and Cost Recovery Account 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 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 P.U. 31(2010).

Pension deferral

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004).

Cost recovery deferral

The Cost Recovery Deferral balance relates to the conclusion of the following regulatory amortizations which expired in 2010: 2005 Unbilled Revenue, Municipal Tax Liability, Depreciation, Replacement Energy, Purchased Power Unit Cost Reserve and 2008 GRA Costs. Expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000. On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of the above mentioned deferrals. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 46(2009). In P.U. 30 (2010), the Board approved the deferred recovery, until a further Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which is to be charged with the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differ from the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. In P.U. 22 (2011), the Board approved the deferred recovery, until a further Order of the Board, of an additional $2,363,000 in 2012 due to the conclusion in 2010 of the amortizations. In P.U. 13 (2013) the Board approved amortization of these cost recovery deferrals over three years. Amortization of this account commenced in 2013.

Cost of capital cost recovery deferral

The cost of capital cost recovery deferral account reflects the deferred recovery of $2,487,000 reflecting the difference between the 8.38% return on equity currently in customer electricity rates and the 8.80% return on equity approved in P.U. 17 (2012). In P.U. 13 (2013) the Board approved a three year amortization of the cost of capital recovery deferral. Amortization of this account commenced in 2013.

Deferred general rate application costs

In P.U. 13 (2013) the Board approved the deferral of cost related to 2013/2014 GRA as well as amortization of this deferral over a three year period commencing in 2013. Actual costs incurred and deferred were approximately $965,000 with amortization of $321,000 incurred in 2013.

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 P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In 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 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 in 2013 were $2,937,000 (before tax). Amortization of this balance will commence in 2014.

Optional seasonal rate revenue and cost recovery account

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2013 was $137,344. This balance was transferred to the RSA on March 31, 2014 pursuant to the Board's approval in P.U. 10 (2014).

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 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 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 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 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 P.U. 11 2012, to be amortized over 15 years commencing in 2013.

As of December 31, 2013 the regulated asset for employee future benefits was $133,096,000.

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, 2013 was $171,212,000.

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. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year. As at December 31, 2012, the non-reversing Degree Day component has been fully amortized. The balance in the Weather Normalization reserve represents the reversing component, which should tend to zero over time.

In P.U. 13 (2013) the Board approved the amortization of the December 31, 2011 year-end balance of the weather normalization account of $7,006,000 ($5,020,000 after future income tax) over a three year period beginning in 2013, representing an amortization of approximately $2,335,000 ($1,673,000 after future income tax) each year. In addition, commencing in 2013, P.U. 13 (2013) also 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 P.U. 11 (2014) the Board approved the December 31, 2013 net regulatory liability balance in the weather normalization account of $7,081,000 ($5,058,185 net of future income tax).

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 2013 the balance in this account was $130,693,000 (2012 - $126,329,000).

Demand management incentive account

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2013, the variation in the account was a regulatory asset of $383,085. This balance was transferred as a debit to the RSA on March 31, 2014 pursuant to the Board's approval in P.U. 7 (2014).

Excess earnings

Excess earnings are the earnings that exceed the upper limit of the allowed range of return on rate base of 8.10% approved by the Board in P.U. 13 (2013).

As a result of our analysis we note that the average rate base originally filed in Return 3 and Return 13 uses 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 (see Return on Rate Base and Equity, Capital Structure and Interest Coverage for details of revisions). This revised rate base produces excess earnings of $42,000 ($33,000) after tax. In discussions with the Company they have determined the additional excess earnings of $26,000 ($16,000 after tax) reported in Return 13 are immaterial to file a revised return. This represents a benefit to the customer.

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2013 are unreasonable.

Pension Expense Variance Deferral Account

Scope: Review of calculation of the Pension Expense Variance Deferral Account ("PEVDA") and assess compliance with P.U. 43 (2009)

In 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 2013 PEVDA was calculated at $2,081,909. This balance was transferred to the Rate Stabilization Account on March 31, 2013 in accordance with P.U. 43 (2009).

We confirm that the 2013 PEVDA is calculated in accordance with 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 P.U. 31(2010)***

In 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 2013 OPEBVDA was calculated at $452,200. This balance was transferred to the Rate Stabilization Account on March 31, 2013 in accordance with P.U. 31 (2010).

We confirm that the 2013 OPEBVDA is calculated in accordance with P.U. 31 (2010).

Optional Seasonal Rate Revenue and Cost Recovery Account

Scope: ***Review of calculation of the Optional Seasonal Rate Revenue and Cost Recovery Account and assess compliance with P.U. 8 (2011) and P.U. 13 (2013)***

In P.U. 8 (2011) the Board approved Rate #1.1S Domestic Seasonal – Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates (the "TOD Rate Study"). On December 31st of each year from 2011 until further order of the Board, this account is to 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 P.U. 13 (2013) the Board approved to maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until the next general rate application.

In accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the first day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. This application for the disposition of the 2013 balance was filed February 26, 2014, within the deadline.

The Optional Seasonal Rate Revenue and Cost Recovery Account balance at December 31, 2013 was $137,344. This balance was transferred to the Rate Stabilization Account in March, 2014 as approved in P.U. 10 (2014).

We confirm that the 2013 Optional Seasonal Rate Revenue and Cost Recovery Account is calculated in accordance with P.U. 8 (2011).

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 2013 are as follows:

1. Made capital investments of $82 million of which over 50% 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. Continued to install automated meters with remote capabilities in locations that prove difficult to read; 62 meter reading routes have been eliminated to year end 2013.

5. A number of changes were made to materials management structure and processes. Responsibility for the area storekeepers shifted from the area offices to Materials Management to bring renewed focus and more consistent expectations for this role. A new system was implemented which enables online ordering of fire retardant clothing and direct delivery to the employee, which will reduce the time and effort spent by supervisory and warehouse staff. A new requisitioning system has also been implemented.

6. Following the January 11th loss of supply incident, the Company made a number of revisions to its outage response and communication protocol. During large scale outages, a centralized communications hub will bring together Operations, Customer Relations and Corporate Communications representatives. This team will ensure internal and external communication in outage situations is both consistent and timely.

7. A new outage communications software system was deployed late in the 1st quarter. This system, called Informer, provides a number of enhancements, such as customized outage status messages which will improve customer communications.

8. During the 1st quarter, Newfoundland Power added 24 phone lines to receive customer calls for outage information. This will reduce the number of times customers receive a busy signal when contacting the Company during outages.

9. New technology has been used to schedule and dispatch field work for line crews in St. John's since 2011. Based on the success of this pilot, the Company is centralizing dispatch of line work, including new service connections and trouble call response, for all areas in 2013. This involves changes to work processes, roles and technology supporting operations, and is expected to enable customer service and productivity improvements.

10. In June 2013, the Company successfully completed an upgrade to its accounting system, Microsoft Dynamics Great Plains. The last upgrade occurred in October of 2008. Extensive post implementation testing has been completed with no significant issues. The new features of the upgrade will allow for increased efficiency of accounting tasks and improved financial reporting.

11. Replenishment of stock in the area warehouses from Central Stores at Duffy Place in St. John's has been reorganized on a bi-weekly schedule resulting in improved workflows.

12. Customer self-service at www.newfoundlandpower.com was enhanced during the quarter with the deployment of multiple payment arrangement capability. This feature allows eligible customers with accounts in arrears to propose multiple payment arrangements on multiple dates.

13. In May, the Company began scheduling customer appointments for new service connections in the St. John's region.

14. The Company website was updated to position eBills as the primary billing method for new customers. This is part of the on-going initiative to encourage customers to receive their bills electronically.

15. In preparation for the coming storm season, the Company website has been enhanced to allow customers to report a power outage through the website or through a mobile device, without having to speak to a representative.

16. The Company updated its phone system to allow customers to specify the area for which they want outage information if the phone system is unable to identify the area from which the call originates. Extra phone lines and reconfiguration of the automated menu will also reduce the likelihood of customers receiving a busy signal.

17. The Company purchased new safety management software that provides enhanced abilities to track and manage safety programs.

18. Newfoundland Power implemented improvements to the service contact process for building contractors, enabling more proactive identification and prioritization of requirements such as licenses, permits and easements. The new process has resulted in immediate benefits in reduced call durations and field service wait times.

19. Customer Service System improvements in the 4th quarter enabled customers' equal payment plan requests via the Company's website to be processed automatically, with no involvement of customer service staff.

20. All Newfoundland Power line trucks are now equipped with GPS location tracking and real time connectivity, and all trouble calls and streetlight requests are being dispatched to crews electronically. New service connections are being dispatched electronically in five of the Company's eight operating areas, with the last three areas scheduled to be online in 1st quarter 2014.

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 of the company:

Category	Measure	Actual 2011	Actual 2012	Actual 2013	Plan 2013	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.57	2.44	2.23	2.53	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.70	1.72	1.71	1.65	No
	Plant Availability (%)	93.5	94.8	93.0	95.9	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	88.5	86.7	86.0	88.0	No
	Call Centre Service Level (% per second)[2]	80/60	80/60	80/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	80.2	84.5	85.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	1.8	1.7	1.1	1.8	Yes
Financial	Earnings (millions)[3]	$33.7	$36.6	$36.6	$35.3	Yes
	Gross Operating Cost/Customer[4]	$241	$238	$243	$243	Yes

[1]2013 reliability statistics reported above exclude the impact of the January Newfoundland and Labrador Hydro system problems and the November blizzard in Central and Western. 2012 reliability statistics reported above exclude the impact of Tropical Storm Leslie. 2011 reliability statistics exclude the impact of a storm in December 2011.
[2] In 2010, Customer Service changed how it monitors answered calls. Service level is now based on calls answered in 60 seconds as opposed to 40 seconds in the original plan.
[3] Excludes $12.8m recovery related to Part VI.I tax
[4] Excluding pension, OPEBs and early retirement costs.

Grant Thornton
2014 Annual Financial Review of Newfoundland Power Inc.

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Board of Commissioners of Public Utilities
2014 Annual Financial Review of
Newfoundland Power Inc.

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Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2014 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 2014 was $964,930,000 compared to average rate base for 2013 of $915,820,000 and 2014 Test Year of $955,416,000. The Company's calculation of the return on average rate base for 2014 was 7.83% (2013 - 8.10%) compared to an approved rate of return of 7.88%. The actual rate of return was within the range approved by the Board (7.70% to 8.06%). The calculations of average rate base and rate of return on average rate base are in accordance with established practice and Board orders. We did note an error in Return 3 of the Company's 2014 Annual Report relating to the omission of excess earnings. This was corrected in the rate base filed in the Company's Schedule D of the 2016 Capital Budget Application.

The Company's calculation of average common equity for 2014 was $429,174,000 (2013 - $414,578,000). The Company's actual return on average common equity for the year ended December 31, 2014 was 9.15% (2013 – 9.16%). In 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 2014 the cost of common equity was 8.8% as per P.U. 13 (2013). The actual return on average common equity for 2014 was 9.15% 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 5.66% over budget in 2014. The capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $5,764,000 (4.82%). However, for each category of expenditure, the variances ranged from an over-budget of 31.50% to an under-budget of 8.10%. Significant variances are explained in our report.

The Company experienced a 5.57% increase in revenue from rates in 2014 as compared to 2013. The increase can be explained by higher electricity sales.

Net operating expenses in 2014 increased by $2,664,000 from 2013 and $4,413,000 over the 2014 Test Year. The increase is primarily due to an increase in labour, conservation and uncollectible bills. These and other 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 2014 are unreasonable.

Non-regulated expenses, net of tax, increased in 2014 by $13,352,300. This variance was largely explained by a change of $12,814,000 in the Part VI.1 tax adjustment allocated by Fortis Inc. among its subsidiaries in 2013 which did not occur in 2014.

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 2014 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

Based on our review, the 2014 Other Post Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with P.U. 31 (2010).

Based on our review, the 2014 Optional Seasonal Rate Revenue and Cost Recovery Account operated in accordance with P.U. 8 (2011).

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 2014 the Company met three out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Outage/Customer (SAIDI) – excluding Hydro loss of supply", "Outage/Customer (SAIFI) – excluding Hydro loss of supply", "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey", "Trouble Call Responded to Within 2 Hours" and "Gross Operating Cost/Customer". The Company excluded the impact of Newfoundland and Labrador Hydro system problems in January.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2014 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,
   - demand side 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 P.U. 19 (2003) and P.U. 32 (2007).

5. Examine the Company's 2014 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 2013-14 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 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 P.U. 31 (2010).

12. Conduct an examination of the Optional Seasonal Rate Revenue and Cost Recovery Account compliance with P.U. 8 (2011) and P.U. 10 (2013).

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;
- examination of, on a test basis where appropriate, documentation supporting amounts included in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

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, 2014 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 3, 2015. 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 28, 2014, the Company filed a revised system of accounts as part of its 2013 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.

We understand that there have been no further changes to the system of accounts since this time.

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

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, 2014 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 of $964,930,000 filed in Schedule D of the 2016 Capital Budget Application differs from the average rate base of $964,955,000 as filed in Return 3 of the Company's 2014 Annual Report to the Board. The revision included on Schedule D resulted in an overall decrease of $25,000 in average rate base as compared to Return 3 due the inclusion of the excess earnings adjustment in Schedule D ($49,000 after tax / 2). Return 3 omitted the excess earnings adjustment in error.

The average rate base for 2014 was $964,930,000 compared to forecast average rate base for 2014 test year of $955,416,000 as approved during the 2013-14 GRA in P.U. 13 (2013). The increase of $9,514,000 (1.00%) above test year is primarily a result of plant investment above forecast. The average rate base for 2013 was $915,820,000.

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 2014; 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 2014, 2014 test year and 2013 (all figures shown are averages):

(000)'s	2014 (1)	2014 Test Year	2013
Net Plant Investment (average)			
Plant Investment	$1,547,173	$1,516,479	$ 1,470,688
Accumulated Depreciation	(634,736)	(622,477)	(613,131)
CIAC's	(32,806)	(33,445)	(31,459)
	879,631	860,557	826,098
Additions to Rate Base (average)			
Deferred Charges (a)	102,584	105,123	100,756
Cost Recovery Deferral for Seasonal/TOD Rates (b)	82	122	94
Cost Recovery Deferral for Hearing Costs (c)	483	625	322
Cost Recovery Deferral for Regulatory Amortizations (d)	1,661	1,661	2,767
Cost Recovery Deferral – 2012 Cost of Capital (e)	883	883	1,472
Cost Recovery Deferral – 2013 Revenue Shortfall (f)	1,689	1,689	1,126
Cost Recovery Deferral – Conservation (g)	3,511	3,583	1,156
Customer Finance Programs (h)	1,250	1,466	1,405
	112,143	115,152	109,098
Deductions from Rate Base (average)			
Weather Normalization Reserve (i)	3,349	2,510	4,931
Other Post-Employment Benefits (j)	27,975	26,006	19,066
Customer Security Deposits (k)	750	830	846
Accrued Pension Obligation (l)	4,480	4,479	4,173
Deferred Income Taxes (m)	2,201	(1,920)	2,188
Excess Earnings (n)	25	-	-
Demand Management Incentive Account (o)	87	-	143
	38,867	31,905	31,347
Average Rate Base before Allowances	952,907	943,804	903,849
Rate Base Allowances			
Materials and Supplies	5,619	6,365	5,445
Cash Working Capital	6,404	5,247	6,526
	12,023	11,612	11,971
Average Rate Base	$ 964,930	$ 955,416	$ 915,820

(1) Revised average rate base filed in Schedule D of the 2016 Capital Budget Application.

(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 $102,584,000 (2013 - $100,756,000) included in the 2014 rate base consists of average deferred pension costs of $102,548,000 (2013 - $100,636,000) and credit facility costs of $36,000 (2013 - $120,000). The Company has included a schedule of these costs in Return 8.

(b) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to 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". The calculation of the 2014 average rate base incorporates $82,000 (2013 - $94,000) related to this deferral account.

(c) In P.U. 13 (2013) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2013, hearing costs related to the 2013/2014 GRA in the amount of $1,250,000. During 2013, the Company deferred $965,000, $285,000 lower than the approved amount, of 2013/2014 GRA hearing costs. The average rate base includes an addition of $483,000 (2013 - $322,000) which represents the unamortized average balance of the original $965,000.

(d) On August 31, 2010 Newfoundland Power submitted an application proposing to defer recovery, until a further Order of the Board, of the amount of $2,363,000 ($1,642,000 after tax) in 2011 to offset the net impact of the expiring amortizations relating to the Municipal Tax Liability, Unrecognized 2005 Unbilled Revenue, Deferred Energy Replacement Costs and the Purchased Power Unit Cost Variance Reserve. This application was approved by the Board in P.U. 30 (2010). P.U. 22 (2011) approved the deferral in 2012 of an additional $2,363,000 ($1,678,000 after tax) related to these expiring amortizations. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Included in the calculation of the average rate base for 2014 is $1,661,000 (2013 - $2,767,000) related to this deferral.

(e) In P.U. 17 (2012) the Board approved the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Included in average rate base for 2014 is $883,000 (2013 - $1,472,000) related to this deferral.

(f) In P.U. 13 (2013) the Board approved the deferral and amortization over three years of amounts related to Newfoundland Power's shortfall in the recovery of revenue requirements for 2013. As a result of this order and updated revenue forecasts subsequently filed by Newfoundland Power in an *Application Filed in Compliance with Order No. P.U. 13 (2013)*, an amount of $3,965,000 ($2,815,000 after tax) has been deferred. Based on a rate implementation date of July 1, 2013, the amortization period has subsequently been updated to 30 months, resulting in amortization for 2014 of $1,126,000 (2013 - $563,000). Included in the calculation of average rate base for 2014 is $1,689,000 (2013- $1,126,000) related to this deferral.

(g) In P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan. These costs were fully amortized in 2013. In 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. Included in the calculation of the average rate base for 2014 is $3,511,000 (2013 - $1,156,000) related to this deferral.

(h) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2014 average rate base incorporates $1,250,000 (2013 - $1,405,000) related to these programs.

(i) During 2014, the Weather Normalization reserve was impacted by the following:

Transfer to RSA

i. In 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 decrease to the reserve of $1,712,000 in 2014 (2013 – $216,000 increase).

Other transfers:

i. $104,000 transfer decrease (2013 – $393,000 increase) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $71,000 transfer increase (2013 - $1,319,000 increase) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

Amortization

i. Also in P.U. 13 (2013) the Board approved a three year amortization of the 2011 balance in the Weather Normalization Reserve of $5,020,000 resulting in a decrease to the reserve of $1,673,000 of amortization for 2014 (2013 - $1,673,000 decrease).

The net impact was a net decrease to the reserve of $3,418,000 (2013 - $255,000 increase). The ending balance in this reserve account totaled $1,640,000 compared to a balance of $5,058,000 at December 31, 2013 (an average of $3,349,000 for 2014 (2013 - $4,931,000)).

(j) Other Post-Employment Benefits is equal to the difference, at December 31, 2014, between the OPEBs liability of $70,979,000 and the OPEBs asset of $38,544,000. The calculation of the 2014 average rate base is equal to the average of the December 31, 2014 net liability of $32,435,000 and the December 31, 2013 net liability of $23,515,000.

(k) 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 2014 average rate base incorporates $750,000 (2013 - $846,000) related to customer security deposits.

(l) The 2014 average rate base calculation incorporates $4,480,000 (2013 - $4,173,000) 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.

(m) In 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 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 2014 average rate base is $1,478,000 and ($7,618,000) respectively. The remaining balance of the deferred income tax liability in the amount of $8,341,000 relates to capital assets. This results in an average balance for deferred income tax liability of $2,201,000 (2013 -

$2,188,000). The average test year balance for 2014 was ($1,920,000), a variance from actual of $4,121,000. The primary reason for this variance relates to the variance in temporary differences in plant investment resulting from fluctuations in CCA claimed.

(n) In 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.

(o) In P.U. 7 (2014) the Board approved the disposition of the 2013 balance of the Demand Incentive Account of $383,085 (($271,990) after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2014. In P.U. 8 (2015) the Board approved the disposition of the 2014 balance of the Demand Incentive Account of $627,503 ($445,527 after tax) by means of a credit to the Rate Stabilization Account as of March 31, 2015. The 2014 average rate base incorporates $87,000 (2013 - $143,000) related to this account.

The net change in the Company's average rate base from 2013 to 2014 can be summarized as follows:

(000's)	**2014**	**2013**
Average rate base - opening balance	**$ 915,820**	$ 883,045
Change in average deferred charges and deferred regulatory costs	**3,200**	4,575
Average change in:		
Plant in service	**76,485**	64,979
Accumulated depreciation	**(21,605)**	(23,813)
Contributions in aid of construction	**(1,347)**	(1,449)
Weather normalization reserve	**1,582**	(19)
Other post employment benefits	**(8,909)**	(8,158)
Future income taxes	**(13)**	(505)
Rate base allowances	**52**	(3,172)
Other rate base components (net)	**(335)**	337
Average rate base - ending balance	**$ 964,930**	$ 915,820

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2014 average rate base, and therefore conclude that the 2014 average rate base included in Schedule D of the Company's 2016 Capital Budget Application is accurate and in accordance with established practice and Board Orders. We did note that Return 3 omitted the excess earnings adjustment in error. This adjustment was subsequently corrected in Schedule D.

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 2014 (based on the revised average rate base of $964,930,000 filed in Schedule D of its 2016 Capital Budget Application) was 7.83% (2013 - 8.10%). 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 2014, the return on average rate base is calculated in accordance with the methodology approved in 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 2012 to 2014 is set out in the table below.

	2014	2013	2012
Actual Return on Average Rate Base	7.83%	8.10%	8.10%
Upper End of Range set by the Board	8.06%	8.10%	8.32%
Lower End of the Range set by the Board	7.70%	7.74%	7.96%

The Board approved the Company's rate of return on average rate base of 7.88% in a range of 7.70% to 8.06% for 2014 in P.U. 23 (2013). As noted above, the Company's actual return on average rate base for 2014 was 7.83% which was inside the range set by the Board.

The 2013 rate of return on average rate base was outside the range set by the Board (2013 actual return on average rate base of 8.1036%) therefore the Company recorded a regulatory liability and decrease in earnings in the amount of $68,000 ($49,000 after tax). As a result of the revised average rate base we calculated excess earnings of $42,000 ($33,000 after tax). In discussions with the Company they determined the additional excess earnings of $26,000 ($16,000 after tax) reported in Return 13 were immaterial to file a revised return. This represents a benefit to the customer. See 'Regulatory Assets and Liabilities' section of our report for further details.

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. We did note that there was no impact on the calculation of the return on average rate base included on Return 13 when calculated with the revised average rate base of $964,930,000 as filed in Schedule D of the Company's 2016 Capital Budget Application.

Capital Structure

In P.U. 13 (2013) the Board reconfirmed its previous position as per P.U. 43 (2009) 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 2014 as reported in Return 24 is as follows:

	2014 Average		**2013**	**2012**
	(000's)	**Percent**	Percent	Percent
Debt	**$532,234**	**54.85%**	54.35%	54.47%
Preferred equity	**8,965**	**0.92%**	0.97%	1.02%
Common equity	**429,174**	**44.23%**	44.68%	44.51%
	$970,373	**100.00%**	100.00%	100.00%

Pursuant to 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 2014 test year in Return 26. The embedded cost of debt for 2014 was 6.99% which represents a 15 bps decrease from 2014 test year embedded cost of debt of 7.14%. This decrease resulted primarily due to lower actual interest on credit facilities over the 2014 test year. Interest on credit facilities was lower than the 2014 test year due to lower short-term borrowing rates and earlier than expected issuance of $70 million in first mortgage sinking fund bonds in November 2013 versus the 2014 test year which anticipated a March 2014 issuance date.

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 Board Order P.U. 13 (2013).

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, 2014 is included on Return 27 of the annual report to the Board. The average common equity for 2014 was $429,174,000 (2013 - $414,578,000). The Company's actual return on average common equity for 2014 was 9.15% (2013 – 9.16%).

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 P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007), P.U. 43(2009) and P.U. 13 (2013).
- recalculated the rate of return on common equity for 2014 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 13 (2013).

In 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 2014 the cost of common equity was 8.80% as per P.U. 13 (2013). The actual return on average common equity for 2014 was 9.15% 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 two years is as follows:

(000's)	2014	2013
Net income	**$ 37,840**	$ 49,920
Income taxes	**10,795**	(2,877)
Interest on long term debt	**36,327**	35,123
Interest during construction	**(1,435)**	(893)
Other interest and amortization of debt discount costs	**880**	1,377
Total	**$ 84,407**	$ 82,650
Interest on long term debt	**$36,327**	$ 35,123
Other interest and amortization of debt discount costs	**880**	1,377
Total	**$37,207**	$ 36,500
Interest Coverage (times)	**2.3**	2.3

The above table shows that the interest coverage did not change from 2013 to 2014.

In 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 2014 is 2.3 times.

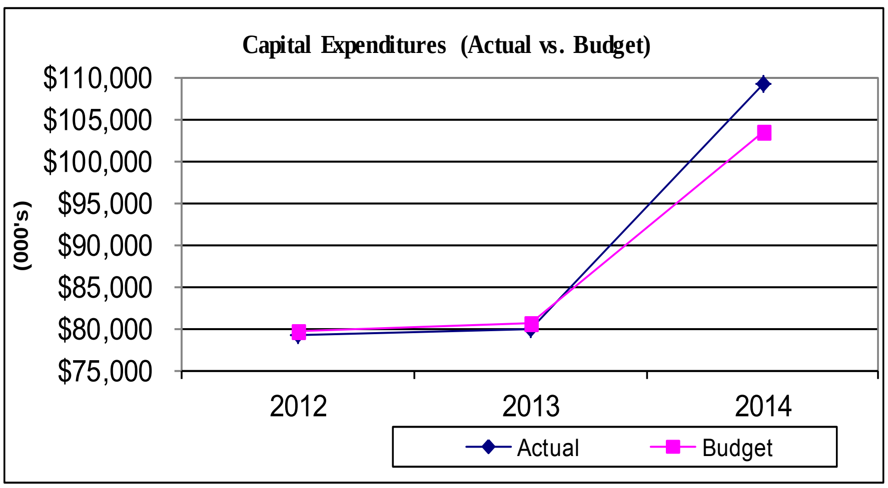
Capital Expenditures

Scope: ***Review the Company's 2014 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 2012 to 2014.

(000's)	2012	2013	2014
Actual	$ 79,290	$ 80,013	**$ 109,429** (1)
Budget	$ 79,690	$ 80,788	**$ 103,572**
Over (under) budget	(0.50%)	(0.96%)	**5.66%**

(1) Total expenditures per the 2014 Capital Budget report include the carryover amount of $2,079,000 for a total of $111,508,000. The carryover amount is made up of four projects: $1,266,000 relating to generation - hydro, $260,000 relating to substations, $142,000 relating to transmission and $411,000 relating to distribution. According to the Company, these expenditures will occur in 2015.



The following table provides a summary of the capital expenditure activity in 2014 as reported in the Company's *"2014 Capital Expenditure Report"*.

	Capital Budget			Actual Expenditures		
(000's)	**2012-2013**	**2014**	**Total**	**2012-2013**	**2014**	**Total**
2014 Capital Projects (1)	$ -	$ 103,572	**$ 103,572**	$ -	$109,429	**$109,429**
2012 and 2013 Projects carried to 2014						
Rattling Brook Dam Refurbishment – 2012	5,000	-	**5,000**	2,957	235	**3,192**
Substation Refurbishment and Modernization – 2013 (2)	4,452	-	**4,452**	3,495	36	**3,531**
Company Building Renovations – 2013 (3)	950	-	**950**	998	576	**1,574**
Stand-by and Emergency Power–Duffy Place – 2013 (4)	160	-	**160**	4	312	**316**
Mobile Radio System Replacement – 2013	750	-	**750**	42	796	**838**
Substation Addition – Portable Substation – Multi Year	4,000	-	**4,000**	830	2,932	**3,762**
Hearts Content Plant Refurbishment – Multi Year	200	-	**200**	144	-	**144**
Transmission Line Rebuild (12L) – Multi Year	380	-	**380**	363	-	**363**
	15,892	-	**15,892**	8,833	4,887	**13,720**
	$15,892	$103,572	**$119,464**	$8,833	$114,316	**$123,149**

(1) Approved by Orders P.U. 27 (2013), P.U. 43 (2013), P.U. 14 (2014) and P.U. 24 (2014).
(2) The Company has noted that the favorable variance to budget relates to a portion of the project that was unable to be completed and was instead resubmitted and approved for completion in the 2015 Capital Budget Application.
(3) The Company has noted that the unfavorable budget variance was a result of mold and asbestos being discovered during the Carbonear service refurbishment.
(4) The Company has noted that the unfavorable budget variance was a result of tender prices being in excess of the budget, even after the scope of the project was modified to encourage additional bidders.

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

(000's)	2014 Budget [1]	2014 Actuals [2]	Variance	Carryover [3]	Variance Including Carryover	%
Generation - Hydro	$ 14,210	$ 11,793	$ (2,417)	$ 1,266	$ (1,151)	(8.10%)
Generation - Thermal	2,010	2,028	18	-	18	0.90%
Substations	26,622	26,695	73	260	333	1.25%
Transmission	5,849	5,757	(92)	142	50	0.85%
Distribution	56,377	61,655	5,278	411	5,689	10.09%
General property	2,222	2,922	700	-	700	31.50%
Transportation	2,570	2,872	302	-	302	11.75%
Telecommunications	849	935	86	-	86	10.13%
Information systems	4,005	4,080	75	-	75	1.87%
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	4,000	4,412	412	-	412	10.30%
Total	$ 119,464	$ 123,149	$ 3,685	$ 2,079	$ 5,764	4.82%

1 - Includes prior years (2012 to 2013) and current year budgeted amounts as there were projects incomplete at the previous year ends.

2 - 2014 actuals include the total expense for projects carried forward from the years 2012 to 2013.

3 - Represents amounts included in the 2014 Budget but not yet spent.

As indicated in the table, capital expenditures were greater than the approved budget (including projects carried over from prior years) on a net basis by $3,685,000 and by $5,764,000 (4.82%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 31.50% for the General Property category to an under-budget of 8.10% for the Generation-Hydro 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 (000s)
Facility Rehabilitation	$ 287
Hydro Plant Production Increase	779
Additions Due to Load Growth	260
Rebuild Transmission Lines	142
Trunk Feeders	261
Feeder Additions for Growth	150
Hearts Content Plant Refurbishment	200
Total Carryover	**$ 2,079**

The Company has provided detailed explanations on budget to actual variances in its "2014 Capital Expenditure Report". For a complete review of the budget variance we refer the reader to this report, Appendix A.

The more significant variances noted above were as a result of the following:

Generation - Hydro

- The favorable variance of $2,417,000 is primarily due to project costs being carried over to 2015 totaling $3,074,000; $1,266,000 relating to 2014 projects and $1,808,000 relating to prior year projects. Of costs incurred in 2014, there was an unfavourable variance of $657,000, which is primarily due to an increase of $429,000 on the Hearts Content Plant Refurbishment, caused by more excavation and construction materials being required that originally expected.

Distribution

The unfavorable variance in Distribution of $5,278,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 11,689	$ 15,467	$ 3,778	32.32%
Meters	2,755	3,003	248	9.00%
Services	3,930	3,844	(86)	(2.19%)
Street Lighting	2,480	2,747	267	10.77%
Transformers	6,995	7,106	111	1.59%
Reconstruction	3,787	5,041	1,254	33.11%
Rebuild Distribution Lines	3,462	4,338	876	25.30%
Relocate/Place Distribution Lines for Third Parties	2,616	2,077	(539)	(20.60%)
Trunk Feeders	1,261	1,544	283	22.44%
Feeder Additions for Growth	1,102	1,360	258	23.41%
Distribution Feeder Improvements	1,587	1,553	(34)	(2.14%)
Bell Island Cable Replacement	14,520	13,367	(1,153)	(7.94%)
AFUDC	193	208	15	7.77%
Total	$ 56,377	$ 61,655	$ 5,278	9.36%

- The unfavorable variance in "Extensions" of $3,778,000 is primarily due to additional distribution extensions that were required to be constructed during the year. In addition, extensions to Nalcor's Soldiers Pond Inverter site and the Bai de L'Eau cottage area were required during the year but had not been budgeted. These two projects totaled $1,647,000. Contributions in aid of construction have been approved by the Board for both projects.

- The unfavorable variance in "Street Lighting" of $267,000 is due to increased costs associated with the installation of street light poles.

- The unfavorable variance of $1,254,000 in "Reconstruction" is a result of additional work being completed during the year. The budget is based on a historical five-year average, however high priority work that was identified during the inspection process exceeded the previous years' average.

- The unfavorable variance of $876,000 in “Rebuild Distribution Lines” is also a result of additional work being completed during the year. The budget is based on a historical five-year average, however high priority work that was identified during the inspection process exceeded the previous years’ average.

- The favorable variance of $539,000 in “Relocate/Place Distribution Lines for Third Parties” is attributable to a joint use partner reducing its 2014 Capital Program due to economic constraints.

- The unfavorable variance of $283,000 in “Trunk Feeders” is due primarily to increased costs for two projects. The relocation of the underbuilt lines from transmission line 12L was $218,000 over budget due to a design change that the Company believes is consistent with long-term least cost, reliable operation of the electrical system. The Manhole Cover Replacement project was $207,000 over budget due to unexpected repairs of the bedding below manhole covers. These increases in cost were partially offset by budgeted expenditures for 2014 being carried over to 2015.

- The unfavorable variance of $258,000 in “Feeder Additions for Growth” is due primarily to increased costs relating to three feeder upgrades and additions: the CLV-03 feeder upgrade; the MMT-01 feeder extension; and the GDL-08 feeder extension. There were various causes for each of the increases, including higher costs to reduce business interruption, design changes, increased costs for materials over budget and municipal planning requirements.

General Property

- The unfavorable variance of $700,000 is primarily due to an increase of $624,000 to complete the Company Building Renovations project. The increase results from the discovery of mold and asbestos at the Carbonear service building.

Transportation

- The unfavorable variance of $302,000 is due to an increase in the cost to purchase vehicles and aerial devices. The increase is attributable to a change in the specifications used to purchase light duty vehicles, as well as the mix of off-road vehicles that were replaced in 2014.

Allowance for Unforeseen Items

- The favorable variance of $750,000 resulted from no instances where the Company had to use this allowance.

General expenses capitalized

- The unfavorable variance of $412,000 is related to an increase in the allocated portion of pension expense. Pension expenses increased as a result of a lower discount rate being used to determine the Company’s accrued obligation under its defined benefit pension plan.

Adherence to Capital Budget Application Guidelines

Based on our review, the Company’s 2014 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 (0.96%) in 2013 and 5.66% in 2014 resulting in no additional reporting requirements.

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 2014 calendar year.

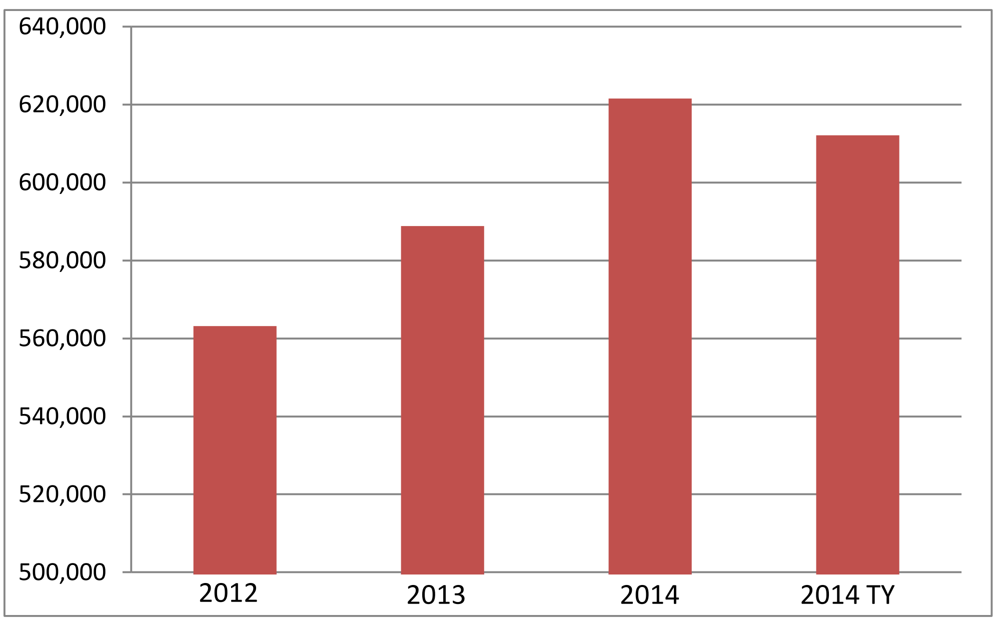
Revenue

Scope: ***Review the Company's 2014 revenue in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues for 2012 to 2014 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2012	2013	2014	2014 Test Year
Residential	$ 348,325	$ 367,550	**$ 390,614**	**$ 385,040**
General services				
0-100kW [1]	80,828	81,625	**82,080**	**82,151**
110-1000kVA	80,641	83,223	**88,789**	**87,528**
Over 1000kVA	34,664	36,961	**39,743**	**38,990**
Street lighting	13,968	14,633	**15,262**	**15,075**
Forfeited discounts	2,737	2,844	**3,016**	**3,356**
Revenue from rates	$ 561,163	$ 586,836	**$ 619,504**	**$ 612,140**
Year over year percentage change	1.56%	4.57%	**5.57%**	

[1] In prior years the Company had reported sales from 0-10kW separately from sales from 10-100 kW. In 2014, the Company reported this data as a single line item, ranging from 0-100 kW.



The above graph demonstrates that the Company has seen a 5.57% increase in revenue from rates in 2014 as compared to 2013. The increase reflects higher electricity sales and the rebasing of customer rates effective July 1, 2013 due to the implementation of 2013/14 GRA order. There was a 2.35% increase in the overall demand in GWh for 2014. For residential sales there was an increase of 6.28% in 2014 revenue from 2013. GWh sold in this category increased by 2.33%, and the number of residential customers increased by 1.27%.

The comparison by rate class of 2014 actual revenues to 2014 Test Year is as follows:

(000's)	Actual 2013	Actual 2014	Test Year 2014	Actual - Test Year Variance	%
Residential	$ 367,550	**$ 390,614**	**$ 385,040**	**$ 5,574**	**1.45%**
General service					
0-100kW	81,625	**82,080**	**82,151**	**(71)**	**-0.09%**
110-1000kva	83,223	**88,789**	**87,528**	**1,261**	**1.44%**
Over 1000kva	36,961	**39,743**	**38,990**	**753**	**1.93%**
Street lighting	14,633	**15,262**	**15,075**	**187**	**1.24%**
Forfeited discounts	2,844	**3,016**	**3,356**	**(340)**	**-10.13%**
Total revenue from rates	$ 586,836	**$ 619,504**	**$ 612,140**	**$ 7,364**	**1.20%**

We have also compared the 2014 test year forecast energy sales in GWh to the actual sold in 2014.

	Actual 2013	Actual 2014	Test Year 2014	Actual - Test Year Variance	%
Residential	**3,530.6**	**3,613.1**	**3,557.3**	55.8	1.57%
General service					
0-100kW	**778.0**	**782.8**	**793.5**	(10.7)	-1.35%
110-1000kva	**939.9**	**965.1**	**955.8**	9.3	0.97%
Over 1000kva	**483.3**	**505.6**	**497.9**	7.7	1.55%
Street lighting	**31.5**	**31.9**	**31.1**	0.8	2.57%
Total energy sales	**5,763.3**	**5,898.5**	**5,835.6**	62.9	1.08%

Actual 2014 revenue from rates was higher than test year with an overall increase in actual sales of $7,364,000 (1.20%) from the 2014 Test Year. There was a 1.08% increase in GWh sold in 2014 compared to 2014 Test Year. The largest variances in revenue can be seen in the residential and 110-1000kva classes where actual revenues increased by $5,574,000 (1.45%) and $1,261,000 (1.44%), 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.

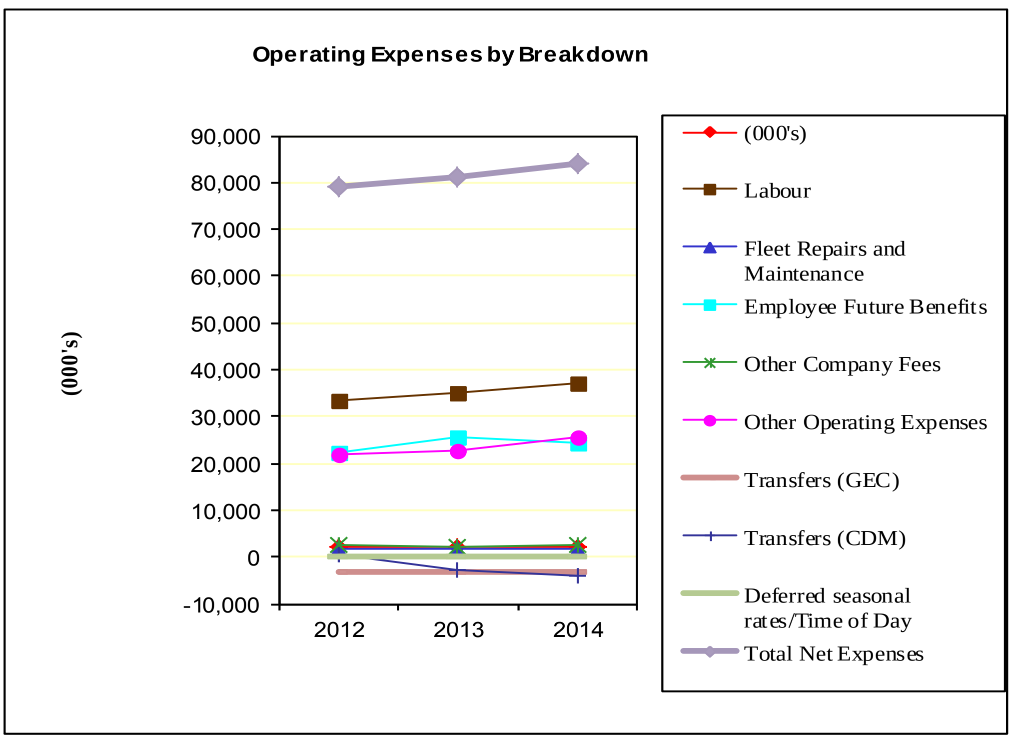
(000's)	2014 Actual	2014 Test Year	2013 Actual	Variance Actual - Test	Variance 2014 - 2013
Labour	$ 37,871	$ 36,376	$ 35,918	$ 1,495	$ 1,953
Reclass OPEB labour cost	(658)	(600)	(663)	(58)	5
Total Labour	37,213	35,776	35,255	1,437	1,958
Vehicle expense	1,901	1,898	1,881	3	20
Operating materials	1,857	1,722	1,568	135	289
Inter-company charges	1,710	1,422	1,184	288	526
Plants, Subs, System Oper & Bldgs	2,312	2,162	2,153	150	159
Travel	1,318	1,315	1,297	3	21
Tools and clothing allowance	1,192	1,138	1,141	54	51
Miscellaneous	1,970	1,780	1,751	190	219
Conservation	1,762	1,800	1,250	(38)	512
Taxes and assessments	1,040	1,037	1,011	3	29
Uncollectible bills	1,490	915	897	575	593
Insurance	1,243	1,216	1,197	27	46
Severance & other employee costs	58	102	84	(44)	(26)
Education, training, employee fees	310	403	392	(93)	(82)
Trustee and directors' fees	431	408	397	23	34
Other company fees	2,650	2,449	2,024	201	626
Stationery & copying	266	321	308	(55)	(42)
Equipment rental/maintenance	769	746	677	23	92
Communications	3,220	3,192	3,074	28	146
Advertising	1,444	1,579	1,113	(135)	331
Vegetation management	1,789	1,935	1,993	(146)	(204)
Computing equipment & software	915	822	799	93	116
Total other	29,647	28,362	26,191	1,285	3,456
Pension & early retirement program	13,276	11,622	14,744	1,654	(1,468)
OPEB's	10,968	10,436	10,880	532	88
Total employee future benefits	24,244	22,058	25,624	2,186	(1,380)
Total gross expenses	$ 91,104	$ 86,196	$ 87,070	$ 4,908	$ 4,034
Transfers (GEC)	(3,399)	(3,051)	(3,415)	(348)	16
CDM amortization	420	438	339	(18)	81
Deferred CDM program costs	(4,436)	(4,401)	(2,937)	(35)	(1,499)
Deferred seasonal rates/TOD	(39)	(40)	(71)	1	32
Deferred regulatory costs	322	417	322	(95)	-
Total net expenses	$ 83,972	$ 79,559	$ 81,308	$ 4,413	$ 2,664

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2013, Test Year 2014 and 2014 Actual.

Net operating expenses in 2014 increased by $2,664,000 from 2013 due primarily to an increase in labour, uncollectible bills and other company fees. Expenses increased by $4,413,000 in comparison to the 2014 test year, primarily due to an increase in labour, uncollectible bills and the pension & early retirement program. These and other 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 2014 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 shows the trend in operating expenses by breakdown for the period 2012 to 2014.

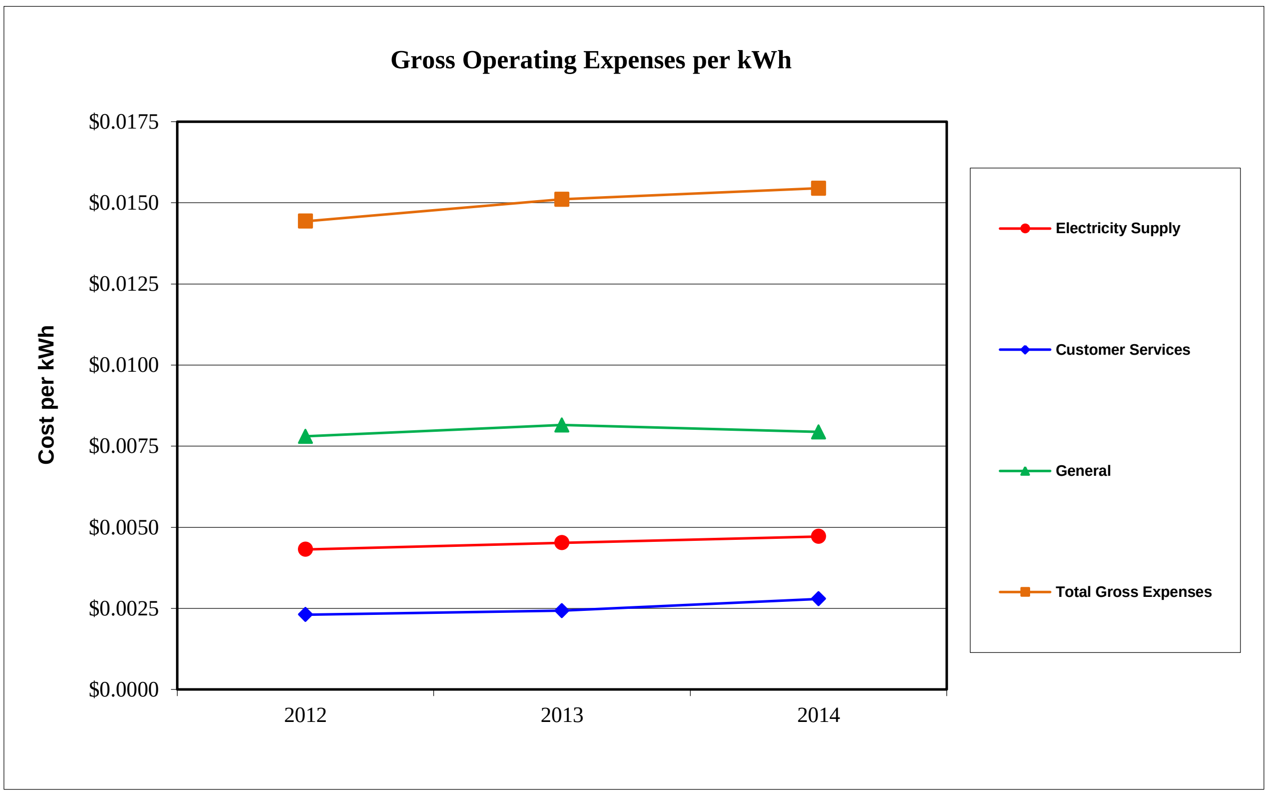
	Actual		
(000's)	**2012**	**2013**	**2014**
Labour	$ 33,549	$ 35,255	**$ 37,213**
Fleet Repairs and Maintenance	1,827	1,881	**1,901**
Employee Future Benefits	22,170	25,624	**24,244**
Other Company Fees	2,488	2,024	**2,650**
Other Operating Expenses	21,788	22,608	**25,418**
Transfers (GEC)	(3,120)	(3,415)	**(3,399)**
Transfers (CDM)	339	(2,598)	**(4,016)**
Deferred seasonal rates/Time of Day	(84)	(71)	**(39)**
Total Net Expenses	$ 78,957	$ 81,308	**$ 83,972**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2012 to 2014 is presented in the table below.

Comparison of Gross Operating Expenses to Total kWh Sold

		Electricity Supply		Customer Services		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
2012	5,652,200	$ 24,420	$0.0043	$ 13,052	$0.0023	$ 44,097	$0.0078	$ 81,569	$0.0144
2013	5,763,300	$ 26,072	$0.0045	$ 14,009	$0.0024	$ 46,989	$0.0082	$ 87,070	$0.0151
2014	5,898,500	$ 27,817	$0.0047	$ 16,478	$0.0028	$ 46,809	$0.0079	$ 91,104	$0.0154



The table and graph show that total gross expenses per kWh have increased by approximately 2% compared to 2013. This is largely due to an increase in Customer Services costs primarily due to the expansion of customer energy conservation programming and an increase in Electricity Supply costs primarily due to an increase in labour associated with restoration following the loss of generation supply with Newfoundland and Labrador Hydro ("Hydro"), power interruptions in January 2014 and normal labour inflation.

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 2012 to 2014 (including 2014 plan) is as follows:

	Actual 2014	Plan 2014 (Note 1)	Actual 2013	Actual 2012	Actual - Plan	Actual 2014-2013
Executive Group	**5.8**	**6.0**	6.0	6.7	(0.2)	(0.2)
Corporate Office	**22.3**	**22.2**	21.0	19.2	0.1	1.3
Finance	**90.9**	**90.7**	89.1	72.3	0.2	1.8
Engineering and Operations	**424.4**	**425.6**	422.1	439.1	(1.2)	2.3
Customer Relations	**72.9**	**64.1**	62.0	60.3	8.8	10.9
	616.3	**608.6**	600.2	597.6	7.7	16.1
Temporary employees	**48.5**	**57.3**	55.6	55.0	(8.8)	(7.1)
Total	**664.8**	**665.9**	655.8	652.6	(1.1)	9.0
Year over year percentage change	**1.37%**	**-**	0.49%	1.95%		

Note 1: The Plan FTEs represents the Company's budget FTEs for 2014 and differs from the test year 2014. The plan provided by Newfoundland Power reflects the Company's budget FTEs updated in 3rd Quarter of 2014, a year after the preparation of the 2014 test year FTE data. The total FTE test year was 656.8 FTEs.

The overall number of FTE's in 2014 compared to 2013 increased by 9.0. The budgeted number of FTE's in the 2014 Plan was 665.9 versus actual of 664.8. The variances between 2014, 2014 Plan and 2013 are the result of the following:

- The Corporate Office is higher than 2013 due primarily to the full-year impact of the Manager of Corporate Communications position hired during the fall of 2013 and the transfer of CDM responsibility from a Corporate employee to a Finance employee.
- Finance is higher than 2013 due primarily to a shift from temporary employees to regular employees.
- Customer Relations is higher than Plan 2014 due primarily to an increase in Customer Account Representatives as well as the addition of a Customer Service Analyst. 2014 is higher than 2013 due primarily to a shift from temporary employees to regular employees, the addition of the Customer Service Analyst as well as an expansion of customer energy conservation programming.
- Temporary Employees are lower than both 2013 and Plan 2014 due primarily to a shift from temporary to regular employees in Finance and Customer Relations as well as a reduction in meter readers resulting from automated meter reading strategy efficiencies.

An analysis of salaries and wages by type of labour and by function from 2012 to 2014, including 2014 test year is as follows:

(000's)	Actual 2014	Test Year 2014 (Note 1)	Actual 2013	Actual 2012	Variance Actual-Test	Variance 2014-2013
Type						
Internal labour	$ 62,275	$ 61,129	$ 59,784	$ 57,280	$ 1,146	$ 2,491
Overtime	6,968	4,888	5,228	5,326	2,080	1,740
	69,243	66,017	65,012	62,606	3,226	4,231
Contractors	18,286	8,928	13,613	11,192	9,358	4,673
	$ 87,529	$ 74,945	$ 78,625	$ 73,798	$ 12,584	$ 8,904
Function						
Operating	$ 37,871	$ 35,421	$ 35,918	$ 34,052	$ 2,450	$ 1,953
Capital and miscellaneous	49,658	39,524	42,707	39,746	10,134	6,951
Total	$ 87,529	$ 74,945	$ 78,625	$ 73,798	$ 12,584	$ 8,904
Year over year percentage change	11.32%		6.54%	5.94%		

Note 1: The test year 2014 excludes non-regulated labour of $355,000 and is presented after reclassification of the OPEB labour cost of $600,000.

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 2014 were $8,904,000 (11.32%) higher than 2013.

Internal labour costs in 2014 were higher than 2013 by 4.17% primarily due to normal salary increases and costs associated with restoration and customer service response following the loss of generation supply from Hydro.

Overtime was higher than 2013 due primarily to the loss of generation supply from Hydro and increased substation work for refurbishment and load growth.

Contract labour increased over 2013 due primarily to increased distribution work associated with the Bell Island Cable replacement.

Also, according to the table above, the 2014 total labour costs was $12,584,000 more than the 2014 test year, representing a 16.79% increase. According to the Company, the increases in 2014 labour over the 2014 test year resulted due to the following:

- Internal labour increased primarily due to increased staffing related to increased capital programs.
- Overtime increased primarily as a result operating labour associated with restoration following the loss of generation supply from Hydro, increased peak load management, inclement weather conditions and a higher number of trouble calls.
- Contract labour increased due to an increase in the 2014 capital program as compared to test year. The Company's workforce only increased by 8 FTEs from test year and the shortfall in labour was made up with contractors.

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 2012 to 2014, including 2014 test year are included in the table below:

(000's)	Salary Cost Per FTE					
	Actual 2014	**Test Year 2014**	Actual 2013	Actual 2012	Variance Actual-Test	Variance 2014-2013
Total reported internal labour costs	**$ 62,275**	**$ 61,129**	$ 59,784	$ 57,280	$ 1,146	$ 2,491
Benefit costs (net)	**(7,448)**	**(8,052)**	(7,502)	(7,074)	604	54
Other adjustments	**(646)**	**(528)**	(571)[1]	(525)	(118)	(75)
Base salary costs	**54,181**	**52,549**	51,711	49,681	1,632	2,470
Less: executive compensation	**(1,932)**	**(1,751)**	(1,893)	(1,806)	(181)	(39)
Base salary costs (excluding executive)	**$ 52,249**	**$ 50,798**	$ 49,818	$ 47,875	$ 1,451	$ 2,431
FTE's (including executive members)	**664.8**	**656.8**	655.8	652.6		
FTE's (excluding executive members)	**661.0**	**652.8**	651.8	648.6		
Average salary per FTE	**81,500**	**80,008**	78,951	76,128		
% increase	**3.36%**		3.71%	3.96%		
Average salary per FTE (excluding executive members)	**79,045**	**77,816**	76,531	73,813		
% increase	**3.42%**		3.68%	3.92%		

[1] 2013 adjustments have been restated to include Performance Share Unit expense recorded in labour

The above analysis indicates that for 2014 the rate of increase in average salary per FTE has been fairly consistent from 2012 to 2014.

During 2014, the Company negotiated a new collective agreement with its union that was ratified in 2015.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2012 to 2014 and the targets set for 2014:

Measure	Target 2014	Actual 2014	Actual 2013	Actual 2012
Controllable Operating Costs/Customer	**$224.6**	$223.9	$217.6	$222.2
Earnings	**36.3m**	37.3m	36.5m	34.2m
Reliability - Duration of Outages (SAIDI)	**2.41**	2.44	2.23	2.44
Customer Satisfaction - % Satisfied	**86.3%**	83.5%	85.9%	86.7%
Customer Satisfaction - 1st Call Resolution	**-**	-	-	88.7%
Injury Frequency Rate	**0.76**	0.51	0.52	1.74
Regulatory Performance	**Subjective**	150%	150%	-

The 2014 STI results were adjusted to remove the impact of Hydro's Supply Loss in January 2014 and reliability was adjusted for the impact of severe winds in 2014. Additionally, STI results were adjusted at the discretion of the Board to reflect the corporate and operational efforts and performance during the supply shortage issues in 2014. In 2013, First Call Resolution was replaced with Regulatory Performance. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or cost based analyses. For 2014, the key determinants of the result of 150% were as follows: (i) the company's participation in the Board's investigation into system reliability initiated in 2014 including the findings in the Board's consultant's December 2014 report (ii) the 2015 capital budget application, and (iii) the Company's efforts in participating in Newfoundland & Labrador Hydro's General Rate Application.

The Company's STI program also includes an individual performance measure for Executives and Managers. 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%
Other Executives	50%	50%
Managers	50%	50%

The individual measures of performance for Managers 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 2014 is established as a percentage of base pay for the three employee groups. For 2014, measures relating to 'controllable operating costs/customer', 'earnings', 'safety' and 'regulatory performance' metrics were met, however the 'customer satisfaction' and "SAIDI" metrics fell below target.

1 The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for
2 2012 to 2014:

STI Payout

	Target 2014	Actual 2014	Target 2013	Actual 2013	Target 2012	Actual 2012
President	40%-50%	64.0%	50%	70.0%	50%	70.0%
Executive	35%	44.8%	35-40%	52.1%	35-40%	51.1%
Managers	15%	19.2%	15%	21.2%	15%	20.2%

3
4
5 STI actual payout rates for 'president', 'executive' and 'manager' employee groups are lower than in the prior
6 year; however, each payout rate exceeded target.

In dollar terms, the STI payouts for 2012 to 2014 are as follows:

	Actual 2014	Actual 2013	Actual 2012	Variance 2014-2013
President [1]	**$ 360,000**	$ 294,000	$ 280,000	$ 66,000
Executive	**312,000**	404,000	381,000	(92,000)
Managers	**320,300**	302,000	271,000	18,300
Total	**$ 992,300**	$ 1,000,000	$ 932,000	$ (7,700)
Year over year percentage change	**-0.77%**	7.30%	18.17%	

[1] 2014 includes two payouts as a new president was appointed effective August 1, 2014

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In 2014, the non-regulated portion (before tax adjustment) was $272,588 (2013 - $285,225).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2012 to 2014.

	Base Salary	Short Term Incentive	Other	Total
2014				
Total executive group	$ 1,268,257	$ 672,000	$ 131,845	$ 2,072,102
Average per executive (4)	**$ 317,064**	**$ 168,000**	**$ 32,961**	**$ 518,026**
2013				
Total executive group	$ 1,195,019	$ 698,000	$ 126,744	$ 2,019,763
Average per executive (4)	**$ 298,755**	**$ 174,500**	**$ 31,686**	**$ 504,941**
2012				
Total executive group	$ 1,145,021	$ 661,000	$ 129,201	$ 1,935,222
Average per executive (4)	**$ 286,255**	**$ 165,250**	**$ 32,300**	**$ 483,806**
% Average increase 2014 vs 2013	**6.13%**	**(3.72%)**	**4.02%**	**2.59%**

Base salary for the executive group increased from 2013 due to salary increases approved by the Board of Directors. Base salaries have been agreed to the 2014 Board of Directors' minutes, and STI payouts have been agreed to the 2015 Board of Directors' minutes.

Company Pension Plan

For 2014, we reviewed the accounts supporting the gross charge of $13,276,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2012 to 2014, including the 2014 test year is as follows:

	Actual 2014	Test Year 2014	Actual 2013	Actual 2012	Variance Actual-Test	Variance 2014-2013
Pension expense per actuary	$ **11,084,000**	$ **9,778,000**	$ 12,744,000	$ 11,153,000	$ 1,306,000	$ (1,660,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**568,000**	**502,000**	560,000	484,934	66,000	8,000
Group RRSP @ 1.5%	**422,000**	**514,000**	440,000	459,000	(92,000)	(18,000)
Individual RRSP's	**1,211,000**	**878,000**	1,013,000	813,000	333,000	198,000
Less: Refunds (net of other expenses)	**(9,000)**	**(50,000)**	(13,000)	(14,000)	41,000	4,000
Total	$ **13,276,000**	$ **11,622,000**	$ 14,744,000	$ 12,895,934	$ 1,654,000	$ (1,468,000)
Year over year percentage change	-9.96%		14.33%	11.50%		
% increase Actual 2014 vs Test Year		14.23%				

Overall, pension expense for 2014 is lower than 2013 primarily due to a higher discount rate at December 31, 2013, which is used to determine the pension obligation for 2014. The pension expense for 2014 increased compared to 2014 test year primarily due to a reduction in the expected return on plan assets. Test year forecasts included an assumption of a 6.50% return on assets, whereas the 2014 actual cost reflected an assumption of 6.25% return on assets. According to Newfoundland Power, the decrease in expected long-term rate of return reflects the Company's long-term investment strategy to increase the fixed income asset portfolio.

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 P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses increased by 1.43% in 2014.

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 19.5% 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 $180,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2013 was primarily the result of wage increases and new hires in the year. This was partially offset by retirements and terminations (there were 31 retirements in 2014). The net increase for RRSP expenditures in 2014 compared to test year of approximately $241,000 is due to new hires in the 5.75% Plan who are replacing retired employees in the 1.5% Plan. According to the Company, the 2014 test year forecast for RRSP contributions in both the Group and Individual Plans was calculated using a straight 4% indexing factor on top of prior year actual amounts, which in the past has provided a reliable estimate that was in line with the actual costs that were incurred. 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).

Severance and other employee costs

The severance and other employee costs incurred by the Company over the period from 2012 to 2014, including 2014 test year are as follows:

(000's)	Actual 2014	Test Year 2014	Actual 2013	Actual 2012	Variance Actual-Test	Variance 2014-2013
Terminations and Severance	**$ 41**	**$ 92**	$ 68	$ 100	$ (51)	$ (27)
Other Retiring Allowance Costs	**17**	**10**	16	14	7	1
Total	**$ 58**	**$ 102**	$ 84	$ 114	$ (44)	$ (26)
Year over year percentage change	-30.95%		-26.32%	-76.97%		
Actual 2014 verses Test Year 2014		-43.14%				

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 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 2012 to 2014, including the 2014 test year is as follows:

(000s)	2014 Actual	2014 Test Year	2013 Actual	2012 Actual	Variance Actual - Test	Variance 2014-2013
Accrued OPEBs	**$ 8,038**	**$ 7,412**	$ 7,957	$ 6,212	$ 626	$ 81
Amortization of transitional balance	**3,504**	**3,504**	3,504	3,504	-	-
Amount capitalized	**(574)**	**(480)**	(581)	(442)	(94)	7
	$ 10,968	**$ 10,436**	$ 10,880	$ 9,274	$ 532	$ 88

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) and P.U. 43 (2009);
- compared intercompany charges for the years 2012 to 2014 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2014 and investigated any unusual items;
- vouched a sample of transactions for 2014 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 2012 to 2014 for charges to and from Newfoundland Power Inc.:

	Actual 2014	Actual 2013	Actual 2012	Variance 2014-2013
Charges from related companies				
Regulated	**$ 311,536**	$ 203,300	$ 202,524	$ 108,236
Non-Regulated	**1,990,723**	1,467,175	1,575,092	523,548
Total	**$ 2,302,259**	$ 1,670,475	$ 1,777,616	$ 631,784
Charges to related companies	**$ 336,758**	$ 506,639	$ 659,162	$ (169,881)

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 2014.

- Fortis Inc. estimated its net pool of operating expenses for 2014 in Q4 2013 as part of its annual business planning process 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 evenly based upon 25% of the estimated annual amount.
- Fortis Inc. used actual year-to-date expenditures up to November and estimated December's expenses for the determination of its actual "true up" calculation. Fortis also used actual assets at November 30, 2014 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of December's expenditures had a minimal impact.

During the fourth quarter of 2014, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $1,710,000 and are summarized as follows:

2014 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$849,000	Non-regulated
Director Fees	304,000	Non-regulated
Consulting and Legal fees	175,000	Non-regulated
Trustee Agent Fees	48,000	Regulated
Audit and Other Fees	42,000	Non-regulated
Public Reporting Costs	56,000	Non-regulated
Annual Meeting Expenses	38,000	Non-regulated
Travel (Board and Other)	69,000	Non-regulated
Insurance (D&O)	27,000	Non-regulated
Other Costs	102,000	Non-regulated
	1,710,000	
Less amounts previously billed:		
Q1 2014	313,000	
Q2 2014	313,000	
Q3 2014	313,000	
Q4 2014 balance owing	$ 771,000	

For 2014, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 7.67%, down from 8.85% in 2013.

As detailed above, trustee agent fees for $48,000 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 2012 to 2014 with Fortis Inc.:

Intercompany Transactions (Regulated)	**Actual 2014**	**Actual 2013**	**Actual 2012**	**Variance 2014-2013**
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 48,000**	$ 53,000	$ 52,000	$ (5,000)
Unused Vacation	**108,844**	-	-	108,844
Miscellaneous	**19,749**	14,185	13,362	5,564
	$ 176,593	$ 67,185	$ 65,362	$ 109,408
Year over year percentage change	**162.85%**	2.79%	-6.89%	
Charges to Fortis Inc.				
Printing and stationery	**$ 76**	$ -	$ -	$ 76
Postage and couriers	**25,704**	24,565	24,457	1,139
Staff charges	**43,667**	97,979	201,332	(54,312)
Staff charges - insurance	**38,527**	183,267	203,524	(144,740)
IS Charges	**-**	309	-	(309)
Pole removal and installation	**769**	572	3,606	197
Miscellaneous	**64,713**	6,090	13,367	58,623
	$ 173,456	$ 312,782	$ 446,286	$ (139,326)
Year over year percentage change	**-44.54%**	-29.91%	-27.34%	

The most significant fluctuation from our analysis of regulated charges from Fortis Inc. is primarily due to the transfer of an unused vacation accrual of $108,844 being transferred to Fortis Inc. when the former president moved from Newfoundland Power to Fortis. This charge does not represent a 2014 expense as it was expensed over the employee's service period at Newfoundland Power.

The most significant fluctuation from our analysis of regulated charges to Fortis Inc. is a $144,740 decrease in staff charges - insurance charged to Fortis Inc. This is due to the retirement of Fortis' Director of Risk Management who was employed by Newfoundland Power. This position was moved to Fortis Inc. after this retirement resulting in significantly fewer charges relating to this position during the year. Additionally, staff charges decreased by $54,312 primarily due to the Company's reduced involvement in Fortis' acquisition projects in the United States.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2012 to 2014:

(Non-Regulated)	Actual 2014	Actual 2013	Actual 2012	Variance 2014-2013
Charges from Fortis Inc.				
Director's fees and travel	**$ 373,000**	$ 185,000	$ 219,000	$ 188,000
Annual and quarterly reports	**98,000**	90,000	96,000	8,000
Staff charges	**849,000**	558,000	557,000	291,000
Miscellaneous	**663,602**	634,175	697,130	29,427
	$ 1,983,602	$ 1,467,175	$ 1,569,130	$ 516,427
Year over year percentage change	**35.20%**	(6.50%)	(2.07%)	

Director’s fees and travel increased by $188,000, primarily due to the impact that a 28% increase in Fortis Inc.’s share price had on the Company’s Director’s Deferred Share Unit Plan.

Staff charges increased by $291,000 primarily due to the new executive structure at Fortis Inc. This resulted in an increase in Newfoundland Power’s share of the Executive Vice President, Eastern Canadian and Caribbean Operations salaries and benefits.

The following table provides a summary and comparison of the other intercompany transactions for 2012 to 2014:

Intercompany Transactions (Other)	Actual 2014	Actual 2013	Actual 2012	Variance 2014-2013
Charges to Fortis Properties				
Staff charges	**$ 12,108**	$ -	$ 864	$ 12,108
Staff charges - insurance	**23,753**	30,894	33,089	(7,141)
Stationary costs	**288**	352	529	(64)
Miscellaneous	**790**	2,770	3,134	(1,980)
	$ 36,939	$ 34,016	$ 37,616	$ 2,923
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 34,048**	$ 52,961	$ 58,212	$ (18,913)
Miscellaneous	**1,664**	1,636	8,944	28
	$ 35,712	$ 54,597	$ 67,156	$ (18,885)
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 3,116**	$ 4,091	$ 3,697	$ (975)
Staff charges	**4,986**	16,587	10,658	(11,601)
IS charges	**4,208**	4,080	6,224	128
Miscellaneous	**380**	370	350	10
	$ 12,690	$ 25,128	$ 20,929	$ (12,438)
Charges to Maritime Electric				
Staff charges	**$ 3,813**	$ 6,976	$ 6,418	$ (3,163)
Staff charges - insurance	**1,444**	1,954	10,005	(510)
IS charges	**2,945**	2,856	1,915	89
Miscellaneous	**510**	573	540	(63)
	$ 8,712	$ 12,359	$ 18,878	$ (3,647)
Charges from Maritime Electric				
Staff charges	**$ 34,372**	$ -	$ 33,932	$ 34,372
Miscellaneous	**-**	5,614	5,999	$ (5,614)
	$ 34,372	$ 5,614	$ 39,931	$ 28,758
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 13,973**	$ 4,647	$ -	$ 9,326
Charges to Central Hudson Gas & Electric				
Staff charges - insurance	**$ -**	$ 6,702	$ -	$ (6,702)
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	**$ 648**	$ 6,177	$ -	$ (5,529)
Charges to Fortis US Energy Corp				
Staff charges - insurance	**$ -**	$ 74	$ 1,176	$ (74)

Intercompany Transactions (Other) Cont'd.	Actual 2014	Actual 2013	Actual 2012	Variance 2014-2013
Charges to Fortis Alberta Inc.				
Staff charges - insurance	**$ 76**	$ 3,359	$ 341	$ (3,283)
Miscellaneous	**13,280**	3,650	3,270	9,630
	$ 13,356	$ 7,009	$ 3,611	$ 6,347
Charges from Fortis Alberta Inc.				
Miscellaneous	**$ 37,611**	$ 41,411	$ 30,637	$ (3,800)
Charges to FortisBC Inc.				
Staff charges	**$ -**	$ -	$ 16,023	$ -
IS charges	**11,781**	11,424	13,405	357
Staff charges - insurance	**-**	2,768	715	(2,768)
Miscellaneous	**2,342**	2,363	2,330	(21)
	$ 14,123	$ 16,555	$ 32,473	$ (2,432)
Charges from FortisBC Inc.				
Miscellaneous	**$ 3,322**	$ 8,740	$ -	$ (5,418)
Charges to Fortis BC Holdings				
Staff charges - insurance	**$ 648**	$ 2,882	$ 324	$ (2,234)
Miscellaneous	**6,360**	6,290	6,500	70
	$ 7,008	$ 9,172	$ 6,824	$ (2,164)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 27,113**	$ 54,492	$ 67,524	$ (27,379)
Staff charges - insurance	**120**	11,048	162	(10,928)
Miscellaneous	**-**	1,400	281	(1,400)
	$ 27,233	$ 66,940	$ 67,967	$ (39,707)
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ 17,074**	$ 21,106	$ 5,400	$ (4,032)
Charges to Fortis Turks and Caicos				
Staff charges	**$ 42,391**	$ -	$ 6,638	$ 42,391
Staff charges - insurance	**162**	9,477	16,764	(9,315)
Miscellaneous	**40**	248	-	(208)
	$ 42,593	$ 9,725	$ 23,402	$ 32,868

The most significant fluctuations from our analysis of other intercompany charges for 2014 compared to 2013 are as follows:

- Staff charges to Fortis Properties increased by $12,108 due to the participation of a Newfoundland Power staff member in the strategic review process associated with the sale of Fortis Properties assets.
- Staff charges to Fortis Ontario Inc. decreased by $11,601 from 2013 due primarily to fewer staff members providing services. Additionally, there were fewer travel costs charged to Fortis Ontario related to Newfoundland Power's CEO travel due to the CEO's transfer to Fortis in mid-2014.
- Staff charges from Maritime Electric increased by $34,372 due to labour and travel costs incurred by Maritime Electric when line crews assisted in power restoration efforts in January 2014.
- Staff charges to Caribbean Utilities Co. decreased by $27,379 due to fewer hours being required to complete work and reduced travel expenses related to Newfoundland Power's CEO due to the CEO's transfer to Fortis in mid-2014.
- Staff charges to Fortis Turks and Caicos increased by $42,391 due to services being provided by Newfoundland Power personnel, including transportation, procurement services, business continuity planning and safety/work methods training.

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.	$ 25,000,000	January 20, 2014	January 31, 2014	1.60%	$ 8,984
Fortis Inc.	$ 25,000,000	February 20, 2014	March 12, 2014	1.65%	$ 17,497
Fortis Inc.	$ 33,000,000	March 20, 2014	April 10, 2014	1.65%	$ 20,305
Fortis Inc.	$ 39,000,000	April 21, 2014	May 16, 2014	1.67%	$ 28,239
Fortis Inc.	$ 40,000,000	May 20, 2014	June 20, 2014	1.67%	$ 36,052
Fortis Inc.	$ 30,000,000	June 20, 2014	July 16, 2014	1.67%	$ 21,537
Fortis Inc.	$ 19,500,000	July 21, 2014	August 5, 2014	1.64%	$ 8,957
Fortis Inc.	$ 28,500,000	August 1, 2014	August 20, 2014	1.64%	$ 12,735
	$ 240,000,000				$ 154,306

[1] Interest charged by Fortis is charged at a discount price and includes a stamp fee.

The interest rate charged on each of the loans above was lower than what would have been charged under the Committed Credit Facility.

In Order 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 2014. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2014.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2013/14 General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2014 and noted some exceptions. Only staff charges relating to the Director of Risk Management are charged at $108 per hour, whereas staff charges relating to routine insurance matters (e.g.; coverage queries, damage claims, arranging for insurance certificates) are based on the recovery of fully distributed costs (hourly rate plus 71% markup). The Company noted that they believe this policy to be accordance with Section 6.5 of the Inter-Affiliate Code of Conduct (May 2011) submitted to the Board on June 10, 2011. These charges were further investigated to determine the impact of using a lower rate. It was determined that had the Company charged $108 per hour rather than the fully distributed cost, an additional $13,300 in staff insurance charges to related parties would result in 2014.

The difference in charge methods was only present for a portion of the year, as the Director of Risk Management, who was an employee of Newfoundland Power but responsible for administering the insurance program for the entire Fortis group, retired in February 2014. After this point, these responsibilities were placed with an individual who is employed by Fortis. As such, there were few charges in the year and there will be no charges in future years. Based on the company's current practices, all insurance charges to related parties from February 2014 on would be based on the fully distributed cost methodology discussed above.

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 2014 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2014	Actual 2013	Actual 2012	Variance 2014-2013
Other company fees				
Other company fees	$ 1,791	$ 1,648	$ 1,389	$ 143
Regulatory hearing costs - other	859	376	1,099	483
	$ 2,650	$ 2,024	$ 2,488	$ 626
Year over year percentage change	30.9%	-18.6%	29.2%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 322	$ 322	$ 253	$ -
Year over year percentage change	0.0%	27.3%	0.0%	

Total company fee costs for 2014 were higher than 2013 actual by $626,000 primarily due to increased regulatory activity and the expansion of customer energy conservation programming. 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 2012 to 2014 is as follows:

(000's)	Actual 2014	Actual 2013	Actual 2012	Variance 2014-2013
Miscellaneous	**$ 1,164**	$ 1,048	$ 857	$ 116
Cafeteria and lunchroom supplies	**92**	95	93	(3)
Promotional items	**120**	119	101	1
Computer software	**5**	5	34	-
Damage claims	**259**	241	215	18
Community relations activities	**1**	11	3	(10)
Donations and charitable advertising	**263**	172	221	91
Books, magazines and subscriptions	**33**	33	67	-
Misc. lease payments	**34**	27	33	7
Total miscellaneous expenses	**$ 1,970**	$ 1,751	$ 1,624	$ 219
Year over year percentage change	**12.50%**	7.83%	10.63%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2013 to 2014 these expenses have increased by 12.56% overall, primarily due to the expansion of customer energy conservation programming.

Donations and charitable advertising included in miscellaneous expenses are non-regulated expenses.

Our procedures in this expense category for 2014 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 2014 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2014 Conservation and Demand Management Report with the Board. This report provided a summary of 2014 CDM activities and costs as well as the outlook for 2014.

In 2014, the Company offered five residential customer energy conservation programs. Those customer energy conservation programs for (i) Energy Star windows, (ii) insulation, (iii) high performance thermostats, (iv) heat recovery ventilators ("HRV's") and (v) various small technologies are bundled together for marketing purposes as the takeCharge Energy Savers. The primary objectives of these programs are to reduce space heating energy consumption and provide reductions in peak demand.

Total CDM costs in 2014 totaled $5,588,000 compared to $3,929,000 in 2013, a $1,659,000 increase. The increase that was experienced in 2014 is primarily due to the introduction of the "Small Technologies" residential program introduced in 2014, for which costs were $1,625,000 in 2014. In 2014, $4,437,000 ($3,150,000 after tax) in CDM costs was deferred to be amortized over 7 years as per P.U. 13 (2013).

In 2015, the Company and Hydro plan to complete the update to the Conservation Potential Study that commenced in 2014, and will use the results of the study to update the next five-year plan. In addition the Company plans to evaluate results of the customer energy conservation program which will include a commercial program review by third party evaluators. The Company also stated it will continue to promote and encourage customer participation, including working with the Provincial Government to promote awareness of energy conservation and programs.

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 2014 and 2013, including test year 2014, as follows:

(000's)	Actual 2014	Test Year 2014	Actual 2013	Variance Actual -	Variance 2014-2013
Vehicle expense	**1,901**	**1,898**	1,881	3	20
Operating materials	**1,857**	**1,722**	1,568	135	289
Plants, Subs, System Oper & Bldgs	**2,312**	**2,162**	2,153	150	159
Travel	**1,318**	**1,315**	1,297	3	21
Tools and clothing allowance	**1,192**	**1,138**	1,141	54	51
Conservation	**1,762**	**1,800**	1,250	(38)	512
Taxes and assessments	**1,040**	**1,037**	1,011	3	29
Uncollectible bills	**1,490**	**915**	897	575	593
Insurance	**1,243**	**1,216**	1,197	27	46
Education, training, employee fees	**310**	**403**	392	(93)	(82)
Trustee and directors' fees	**431**	**408**	397	23	34
Stationery & copying	**266**	**321**	308	(55)	(42)
Equipment rental/maintenance	**769**	**746**	677	23	92
Communications	**3,220**	**3,192**	3,074	28	146
Advertising	**1,444**	**1,579**	1,113	(135)	331
Vegetation management	**1,789**	**1,935**	1,993	(146)	(204)
Computing equipment & software	**915**	**822**	799	93	116
Transfers (GEC)	**(3,399)**	**(3,051)**	(3,415)	(348)	16
Transfers (CDM)	**420**	**438**	339	(18)	81
Deferred seasonal rates/Time of Day	**(39)**	**(40)**	(71)	1	32

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

- Operating materials were higher than test year and 2013 primarily due to higher maintenance costs related to the Topsail penstock repairs.
- Plants, Subs, System Oper & Bldgs was higher than test year and 2013 due primarily to increased snow clearing requirements resulting from inclement weather conditions earlier in the year.
- Conservation costs increased from 2013 due primarily to the expansion of customer energy conservation programming.
- Uncollectible bills were higher than test year and 2013 primarily due to an increase in bad debt expenses associated with higher customer account balances during the winter of 2014. In addition, uncollectible bills vary from year to year as a result of general economic conditions.
- Education, training and employee fees decreased from the test year due to more training conducted in-house and the deferral of some training to 2015 due to scheduling conflicts.
- Advertising costs is lower than test year primarily due to cost sharing of television safety advertisements with Hydro as well as timing of advertising activity for energy conservation. It increased from 2013 due primarily to the expansion of customer energy conservation programming.
- Vegetation management costs decreased over 2013 and test year primarily due to timing of vegetation management activity for distribution and transmission.
- Computing equipment & software increased over 2013 and test year due primarily to increases in software maintenance renewal costs as well as additional software purchases.

Other Costs

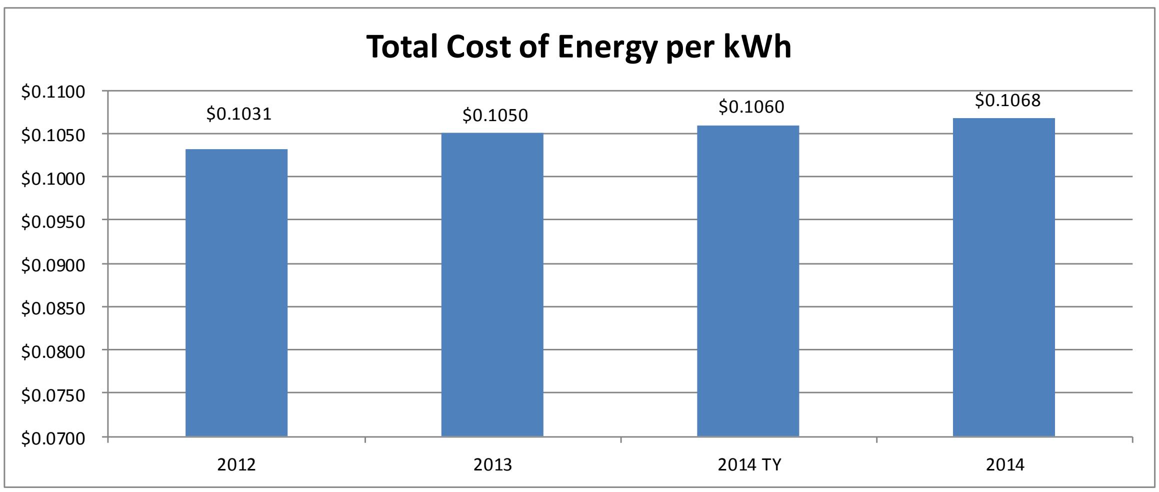
Scope: ***Conduct an examination of purchased power, depreciation, interest and income taxes to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

The following table and graph provide the total cost of energy (expressed in kWh) from 2012 to 2014, including 2014 test year (includes non-regulated):

(000s)

Year	KwH Sold	Operating Expenses	Purchased Power	Deferred Cost Recoveries and Amortizations	Depreciation	Finance Charges	Income Taxes	Net Earnings	Total Cost of Energy	Cost per kWh
2012	5,652,200	$ 78,957	$ 380,374	$ (4,850)	$ 47,372	$ 35,856	$ 8,007	$ 37,204	$ 582,920	$ 0.1031
2013	5,763,300	$ 81,308	$ 390,210	$ (768)	$ 51,300	$ 36,034	$ (2,877)	$ 49,920	$ 605,127	$ 0.1050
2014 TY	5,835,600	$ 79,559	$ 396,863	$ 3,990	$ 48,291 [1]	$ 36,821	$ 15,448 [1]	$ 37,446	$ 618,418	$ 0.1060
2014	5,898,500	$ 83,972	$ 402,843	$ 3,990	$ 53,882	$ 36,450	$ 10,795	$ 37,840	$ 629,772	$ 0.1068

[1] - Actuals for 2012 to 2014 reflect a reclassification between depreciation and income taxes for the income tax effect on the cost of removal for financial reporting purposes. 2014TY does not reflect this adjustment.



Purchased Power

We have reviewed the Company's purchased power expense for 2014 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 $12.6 million, from $390.2 million in 2013 to $402.8 million in 2014. According to the Company, the increase resulted primarily from electricity sales growth.

Purchased power expense for the 2014 test year is $399.2 million compared to $402.8 million in 2014 actuals. This represents an increase of $3.6 million or 0.9%.

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, 2010 and assessed the reasonableness of depreciation expense.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. The study for plant in service as of December 31, 2010 was completed in 2011. The study was included in the 2013-2014 General Rate Application by the Company and was approved in P.U. 13 (2013), including the approval of the accumulated depreciation reserve variance of $2.6 million to be amortized over the average remaining service life of the related assets. The new depreciation rates from the 2010 depreciation study, including the amortization of the accumulated depreciation reserve, were implemented effective January 1, 2013.

Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method in its 2010 depreciation study as this method provides for a better match of depreciation expense and loss in service. The next study for plant in service is to be completed as of December 31, 2014 with its next General Rate Application.

The objective of our procedures in this section was to ensure that the 2014 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2010 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 2014; and,
- assessed the overall reasonableness of the depreciation for 2014.

Amortization expense for 2014 is $53,882,000 as compared to $51,300,000 for 2013, representing a 5.03% increase. The 2014 and 2013 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:

('000s)	2014	2013	Variance 2014-2013	%
Depreciation and amortization as reported	$ 53,882	$ 51,300	$ 2,582	5.03%
Less: Tax on Cost of Removal [1]	(4,594)	(4,336)	(258)	5.95%
Depreciation of Fixed Assets	$ 49,288	$ 46,964	$ 2,324	4.95%

Note 1: Recognised as income tax for financial reporting purposes.

The following table provides a comparison of the depreciation of fixed assets for 2014, 2014 test year and 2013:

('000s)	2014	2014 TY	2013	Variance 2014-2014TY	Variance 2014-2013
Depreciation of Fixed Assets	$ 49,288	$ 48,291	$ 46,964	$ 997	$ 2,324

Depreciation of fixed assets for 2014 is $49,288,000 as compared to $46,964,000 for 2013, representing a 4.95% increase. The change is attributable to an increase of depreciable assets by approximately $90,887,000. The variance of depreciation of fixed assets for 2014 as compared to 2014 test year was $997,000, representing a 2.06% increase. The change is primarily due to an increase in the Company's depreciation expense of its distribution assets which is attributable to an increase of average plant in service distribution assets by approximately $29,660,000 over 2014 test year.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006), P.U. 32 (2007) and P.U. 13 (2013), as well as the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2010 have been incorporated into the Company's depreciation calculations for 2014.

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 2012 to 2014 and 2014 test year:

(000's)	Actual 2014	Test Year 2014	Actual 2013	Actual 2012	Variance Actual - Test	Variance 2014-2013
Interest						
Long-term debt	**$ 36,327**	**$ 36,089**	$ 35,123	$ 35,039	$ 238	$ 1,204
Other	**645**	**897**	1,092	921	(252)	(447)
Amortization						
Debt discount	**254**	**243**	302	337	11	(48)
Interest charged to construction	**(776)**	**(408)**	(483)	(441)	(368)	(293)
Total finance charges	**$ 36,450**	**$ 36,821**	$ 36,034	$ 35,856	$ (371)	$ 416
Year over year percentage change	**1.13%**		0.50%	-0.24%		
Actual 2014 verses Test Year 2014		**-1.01%**				

In the above table, the increase in interest on long term debt compared to 2013 is attributable to the $70 million first mortgage sinking bond issued in 2013, on which a full year's interest has been paid in 2014. The decrease in other interest is due to lower borrowings under the Company's credit facility during the year. The variance of finance charges for 2014 as compared to 2014 test year was $371,000, representing a 1% decrease primarily relating to the increase in the interest charged to construction in 2014.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2014 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2014 and have noted that the effective income tax rate increased from 21.1% in 2013 to 22.2% in 2014. Excluding the impact of the Part V1.1 tax for 2014, 2014 test year and 2013 results in the following effective rates:

('000s)	Actual 2014	Test Year 2014	Actual 2013	Variance Actual - Test	Variance 2014-2013
Income tax expense	$ 10,795	$ 15,448	$ (2,877)	$ (4,653)	$ 13,672
Add back: Part VI.1 tax	-	-	12,814	-	(12,814)
	$ 10,795	$ 15,448	$ 9,937	$ (4,653)	$ 858
Earnings before income taxes	$ 48,635	$ 52,894	$ 47,043	$ (4,259)	$ 1,592
Effective income tax rate excluding Part VI.1 tax	22.2%	29.2%	21.1%	-7.0%	1.1%

With the exclusion of the Part VI.1 tax, the effective rate increased by 1.1% in 2014 compared to 2013 and decreased by 7.0% compared to 2014 test year. The decrease for 2014 from 2014 test year is primarily resulting from increased depreciation expense associated with the future cost of removal of the Company's property, plant and equipment recorded in depreciation expense. There was no change in the statutory tax rate for 2013, 2014 test year and 2014 which remained at 29%.

Upon adoption of U.S. GAAP in 2012, the Company was required to recognize the impact of the difference between enacted tax rates and substantially enacted tax rates related to the allocation of the unregulated Part VI.1 tax deduction from Fortis to Newfoundland Power. This resulted in the Company recording a $12.8 million income tax recovery in 2013.

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 2014 is unreasonable.

Costs Associated with Curtailable Rates

In 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 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 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.

Seventeen customers participated in the Option during the 2013-2014 winter season. The total of the curtailment credits for 2014 was $241,622 compared to the 2013 credits of $222,074. Total operating costs incurred by the Company in 2014 were $255,403 compared to $243,392 for 2013. The curtailment credit total for the 2013-2014 winter season is higher than the previous season's total primarily due to a lower number of curtailment failures this past winter season. There were 12 curtailment failures during this winter season compared to 17 in the winter of 2013. More than half of the curtailment failures in 2013 resulted from customer's standby generation being unavailable when requested, which occurred less frequently in 2014.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and 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 2014 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2014 and investigated any unusual items;
* 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 2014	Actual 2013	Actual 2012	Variance 2014-2013
Charged from Fortis Companies:				
Annual report and quarterly reports	**$ 98,000**	$ 90,000	$ 96,000	$ 8,000
Directors' fees and travel	**373,000**	185,000	219,000	188,000
Hotel/Banquet Facilities	**7,100**	-	5,700	7,100
Staff charges	**849,000**	558,000	557,000	291,000
Miscellaneous	**663,600**	634,200	697,400	29,400
	1,990,700	1,467,200	1,575,100	523,500
Performance Share Unit Plan [1]	**147,400**	65,000	-	82,400
Donations and charitable advertising	**331,100**	221,200	286,800	109,900
Executive short term incentive	**285,200**	257,000	170,200	28,200
Miscellaneous	**46,500**	32,400	79,700	14,100
	2,800,900	2,042,800	2,111,800	758,100
Less: Income taxes	**812,200**	592,400	612,400	219,800
Less: Part VI.1 tax adjustment	**-**	12,814,000	2,589,000	(12,814,000)
Total non-regulated (net of tax)	**$ 1,988,700**	$ (11,363,600)	$ (1,089,600)	$ 13,352,300

[1] The Performance Share Unit (PSU) was introduced in 2013, and the full expense associated with the Plan has be designated as non-regulated. The expense associated with the PSU Plan is not billed to Newfoundland Power by Fortis, which is why it was not included in the Intercompany Transactions Report.

In the table above the most significant fluctuation between 2014 and 2013 pertains to the Part VI.1 tax adjustment. This tax adjustment results from the payment by Fortis of dividends on its preferred shares. The Company has noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.'s corporate tax planning and preferred share dividend payment, and the Company's capacity to cover this tax. The amount for 2013 represented a one-time income tax recovery related to the enactment of proposed corporate income tax rate changes.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2013 this represents an addition to non-regulated expenses (before tax adjustment) of $285,000 (2013 - $257,000). 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 29.0% which agrees with the Company's statutory rate as identified in the 2014 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 2013 and 2014:

(000's)	2014 Actual	2013 Actual	Variance 2014-2013
Regulatory Assets			
Rate stabilization account	**$ 2,342**	$ 12,407	$ (10,065)
OPEBs asset	**38,544**	42,048	(3,504)
Pension deferral	**281**	1,409	(1,128)
Cost recovery deferral	**1,576**	3,150	(1,574)
Cost of capital cost recovery deferral	**828**	1,658	(830)
Revenue shortfall deferral	**1,586**	3,172	(1,586)
Deferred GRA costs	**322**	644	(322)
Conservation and demand management deferral	**6,953**	2,937	4,016
Optional seasonal rate revenue and cost recovery account	**97**	134	(37)
Employee future benefits	**128,237**	133,096	(4,859)
Demand management incentive account	**-**	383	(383)
Weather normalization account	**46**	-	46
Deferred income taxes	**176,707**	171,212	5,495
	$ 357,519	$ 372,250	$ (14,731)
Regulatory Liabilities			
Weather normalization account	**$ 2,335**	$ 7,081	$ (4,746)
Future removal and site restoration provision	**135,357**	130,693	4,664
Demand management incentive account	**628**	-	628
Excess earnings	**68**	68	-
	$ 138,388	$ 137,842	$ 546

<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, 2014 were approved by the Board in P.U. 21 (2014).

As of December 31, 2014, there was a charge to the RSA of $1,838,900 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007) and P.U. 43 (2009).

Pursuant to 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, 2014, the credit balance of $561,760 in the OPEBVDA account was credited to the RSA.

Pursuant to 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, 2014, the balance of $1,161,668 in the PEVDA account was credited to the RSA.

Pursuant to 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, 2014 $2,410,802 was debited to the RSA in accordance with P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account and the Optional Seasonal Rate Revenue and Cost Recovery Account 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 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 P.U. 31(2010).

Pension Deferral

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004).

Cost Recovery Deferral

The Cost Recovery Deferral balance relates to the conclusion of the following regulatory amortizations which expired in 2010: 2005 Unbilled Revenue, Municipal Tax Liability, Depreciation, Replacement Energy, Purchased Power Unit Cost Reserve and 2008 GRA Costs. Expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000. On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of the above mentioned deferrals. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 46(2009). In P.U. 30 (2010), the Board approved the deferred recovery, until a further Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which is to be charged with the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differ from the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. In P.U. 22 (2011), the Board approved the deferred recovery, until a further Order of the Board, of an additional $2,363,000 in 2012 due to the conclusion in

2010 of the amortizations. In P.U. 13 (2013) the Board approved amortization of these cost recovery deferrals over three years. Amortization of this account commenced in 2013.

Cost of capital cost recovery deferral

The cost of capital cost recovery deferral account reflects the deferred recovery of $2,487,000 reflecting the difference between the 8.38% return on equity currently in customer electricity rates and the 8.80% return on equity approved in P.U. 17 (2012). In P.U. 13 (2013) the Board approved a three year amortization of the cost of capital recovery deferral. Amortization of this account commenced in 2013.

Deferred general rate application costs

In P.U. 13 (2013) the Board approved the deferral of cost related to 2013/2014 GRA as well as amortization of this deferral over a three year period commencing in 2013. Actual costs incurred and deferred were approximately $965,000 with amortization of $321,000 incurred in 2013 and $322,000 in 2014.

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 P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In 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 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, 2014 were $6,953,000 (before tax) with amortization of $419,577 in 2014.

Optional Seasonal Rate Revenue and Cost Recovery Account

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2014 was $96,270. This balance was transferred to the RSA on March 31, 2015 pursuant to the Board's approval in P.U. 10 (2015).

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 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 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 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 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 P.U. 11 (2012), to be amortized over 15 years commencing in 2013.

As of December 31, 2014 the regulated asset for employee future benefits was $128,237,000.

<u>Deferred income taxes</u>

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, 2013 was $176,707,000.

<u>Weather Normalization Account</u>

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.

In P.U. 13 (2013) the Board approved the amortization of the December 31, 2011 year-end balance of the weather normalization account of $7,006,000 ($5,020,00 after future income tax) over a three year period beginning in 2013, representing an amortization of approximately $2,335,000 ($1,673,000 after future income tax) each year. In addition, commencing in 2013, P.U. 13 (2013) also 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 P.U. 11 (2015) the Board approved the December 31, 2014 net regulatory liability balance in the Weather Normalization Account of $2,289,000 ($1,640,357 net of future income tax) represented by one year of the remaining life of the December 31, 2011 balance of $2,335,000 less $46,000 relating to 2014 additions to the reserve.

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 2014 the balance in this account was $135,357,000 (2013 - $130,693,000).

Demand Management Incentive Account

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2014, the variation in the account was a regulatory liability of $627,503. This balance was transferred as a credit to the RSA on March 31, 2015 pursuant to the Board's approval in P.U. 8 (2015).

Excess earnings

Excess earnings are the earnings that exceed the upper limit of the allowed range of return on rate base of 8.06% approved by the Board in P.U. 23 (2013).

As a result of our analysis we note that the average rate base originally filed in Return 3 and Return 13 for 2013 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 (see Return on Rate Base and Equity, Capital Structure and Interest Coverage for details of revisions). This revised rate base produces excess earnings of $46,000 ($33,000) after tax. The Company determined the additional excess earnings of $26,000 ($16,000 after tax) reported in the 2013 Return 13 were immaterial to file a revised return. This represents a benefit to the customer.

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2014 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account ("PEVDA") and assess compliance with P.U. 43 (2009)***

In 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 2014 PEVDA was calculated at $1,161,668. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2014 in accordance with P.U. 43 (2009).

We confirm that the 2014 PEVDA is calculated in accordance with 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 P.U. 31(2010)***

In 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 2014 OPEBVDA was calculated at $561,760. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2014 in accordance with P.U. 31 (2010).

We confirm that the 2014 OPEBVDA is calculated in accordance with P.U. 31 (2010).

Optional Seasonal Rate Revenue and Cost Recovery Account

Scope: ***Review of calculation of the Optional Seasonal Rate Revenue and Cost Recovery Account and assess compliance with P.U. 8 (2011) and P.U. 13 (2013)***

In P.U. 8 (2011) the Board approved Rate #1.1S Domestic Seasonal – Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates (the "TOD Rate Study"). On December 31st of each year from 2011 until further order of the Board, this account is to 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 P.U. 13 (2013) the Board approved to maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until the next general rate application.

In accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the first day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. This application for the disposition of the 2014 balance was filed February 26, 2015, within the deadline.

The Optional Seasonal Rate Revenue and Cost Recovery Account balance at December 31, 2014 was $96,270. This balance was approved to be transferred to the Rate Stabilization Account as a charge as of March 31, 2015 in P.U. 10 (2015).

Nothing has come to our attention to indicate that the Company is not in compliance with P.U. 8 (2011).

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 2014 are as follows:

1. Made capital investments of $114 million of which over 50% 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. Continued to install automated meters with remote capabilities in locations that prove difficult to read. Overall, Automated Meter Reading (AMR) penetration has now reached 53.4%. The 2016 Capital Budget application proposes having all non-automated meters replaced by year end 2017.

5. Materials Management completed a radio-frequency identification ("RFID") pilot project. RFID technology allows improved inventory tracking and corporate reporting. The full implementation of this technology is planned as part of the Company's 2015 capital budget application.

6. A new requisitioning system was fully implemented. All approvals are now electronic and vendors are fully connected through a web portal.

7. The Company completed the rollout of centralized dispatch for service work in the three remaining operating areas. Work schedules for service work in all operating areas are now dispatched from a central location and completed by crews using laptops in trucks.

8. Fourteen downline automated distribution feeder sectionalizing reclosers were installed on heavily loaded distribution feeders in the Northeast Avalon to improve flexibility in the operation of Newfoundland Power's distribution feeders.

9. Incoming customer service requests that are technical in nature are now directed to a specific team of Customer Account Representatives (CARs). This is improving customer service and reducing call durations.

10. Work is well underway to update critical infrastructure lists in consultation with the RCMP & RNC. Communication plans for storms & outages have been updated and new joint plans have been developed with Hydro.

11. The Company has developed an advance notification protocol, joint with Hydro, which will remove any doubt as to when both utilities will engage with key stakeholders and customers

12. The Company's mobile website was updated to enable customers to view the past 36 months of bill and letter correspondence. In addition, the ability to submit a meter reading using a mobile device was added during the 3rd quarter.

13. The Company is working with its pole contractors to begin assigning and completing pole installations electronically through the *workingwith.newfoundlandpower.com* website.

14. Newfoundland Power implemented a new outage notification system allowing customers to sign up for power outage alerts through either text messaging or email. This new service applies to feeder and system level outages. This service marks the first outbound notifications at the customer level.

15. All operating areas are now booking appointments for new service connections.

16. Continued to expand the distribution GIS system.

17. Continued the Substation Modernization and Refurbishment program. Five substations were upgraded in 2014. In total, 67% of the distribution feeders are now automated.

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 of the company:

Category	Measure	Actual 2012	Actual 2013	Actual 2014	Plan 2014	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.44	2.23	2.93	2.41	No
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.72	1.71	2.44	1.71	No
	Plant Availability (%)	94.8	93.0	94.4	95.0	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	86.7	86.0	83.5	87.0	No
	Call Centre Service Level (% per second)	80/60	80/60	80/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	84.5	85.0	81.0	85.0	No
Safety	All Injury/Illness Frequency Rate	1.7	1.1	1.2	1.5	Yes
Financial	Earnings (millions)[2]	$36.6	$36.6	$37.3	$36.3	Yes
	Gross Operating Cost/Customer[3]	$238	$243	$259	$250	No

[1]2014 reliability statistics above exclude the impact of the January Newfoundland and Labrador Hydro (NLH) system problems. 2013 reliability statistics reported above exclude the impact of the January NLH system problems and the November blizzard in Central and Western. 2012 reliability statistics reported above exclude the impact of Tropical Storm Leslie.
[2] Excludes $12.8m recovery related to Part VI.I tax in 2013.
[3] Excludes pension, OPEBs and early retirement costs.

The following table compares whether the company measures were achieved during the 2012, 2013, and 2014 years:

Category	Measure	Measure Achieved 2012	Measure Achieved 2013	Measure Achieved 2014
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	Yes	No
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	Yes	No	No
	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 (%)	No	Yes	No
Safety	All Injury/Illness Frequency Rate	No	Yes	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	No	Yes	No

Grant Thornton
2015 Annual Financial Review of Newfoundland Power Inc.

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Board of Commissioners of Public Utilities
2015 Annual Financial Review of Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2015 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 2015 was $1,019,082,000 compared to average rate base for 2014 of $964,930,000 and 2013 of $915,820,000. The Company's calculation of the return on average rate base for 2015 was 7.48% (2014 - 7.83%) compared to an approved rate of return of 7.50%. The actual rate of return was within the range approved by the Board (7.32% to 7.68%). 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 2015 was $451,501,000 (2014 - $429,174,000). The Company's actual return on average common equity for the year ended December 31, 2015 was 8.98% (2014 – 9.15%). In 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 2015 the cost of common equity was 8.80% as per P.U. 13 (2013). The actual return on average common equity for 2015 was 8.98% 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 3.12% over budget in 2015. The capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $6,467,000 (5.34%). However, for each category of expenditure, the variances ranged from an over-budget of 19.29% to an under-budget of 36.59%. Significant variances are explained in our report.

The Company experienced a 3.25% increase in revenue from rates in 2015 as compared to 2014. The increase can be explained by an increase in customer energy rates effective July 1, 2015 combined with higher electricity sales.

Net operating expenses in 2015 increased by $74,000 from 2014. There was a substantial increase in Pension and early retirement expenses but these costs were offset by decreases in Labour and OPEB's costs. These and other 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 2015 are unreasonable.

Non-regulated expenses, net of tax, decreased in 2015 by $189,400. This variance is primarily due to the fact that there was executive stock option expenses of $321,602 in 2014 but there was only $147,009 stock option expenses in 2015.

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 2015 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

Based on our review, the 2015 Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with P.U. 31 (2010).

Based on our review, the 2015 Optional Seasonal Rate Revenue and Cost Recovery Account operated in accordance with P.U. 8 (2011) and P.U. 13 (2013).

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 2015 the Company met six out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Outage/Customer (SAIFI) – excluding Hydro loss of supply", "Plant Availability", "% 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 2015 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,
   - demand side 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 P.U. 19 (2003) and P.U. 32 (2007).

5. Examine the Company's 2015 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 2013-14 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 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 P.U. 31 (2010).

12. Conduct an examination of the Optional Seasonal Rate Revenue and Cost Recovery Account compliance with P.U. 8 (2011) and P.U. 13 (2013).

13. Conduct an examination of the deferred cost recovery relating to the 2012 Cost of Capital in compliance with P.U. 17 (2012) and its amortization in compliance with P.U. 13 (2013).

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, 2015 have been audited by Ernst and Young LLP, Chartered Professional Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 2, 2016. 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 28, 2014, the Company filed a revised system of accounts as part of its 2013 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.

According to the Company there have been no further significant changes to the system of accounts since this time.

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

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, 2015 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 2015 was $1,019,082,000 which is an increase of $54,152,000 (5.61%) over the average rate base for 2014 of $964,930,000. 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 2015; 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 2015, 2014 and 2013 (all figures shown are averages):

(000)'s	2015	2014	2013
Net Plant Investment (average)			
Plant Investment	**$1,629,189**	$1,547,173	$ 1,470,688
Accumulated Depreciation	**(657,233)**	(634,736)	(613,131)
CIAC's	**(33,970)**	(32,806)	(31,459)
	937,986	879,631	826,098
Additions to Rate Base (average)			
Deferred Charges (a)	**101,448**	102,584	100,756
Cost Recovery Deferral for Seasonal/TOD Rates (b)	**59**	82	94
Cost Recovery Deferral for Hearing Costs (c)	**161**	483	322
Cost Recovery Deferral for Regulatory Amortizations (d)	**553**	1,661	2,767
Cost Recovery Deferral – 2012 Cost of Capital (e)	**294**	883	1,472
Cost Recovery Deferral – 2013 Revenue Shortfall (f)	**563**	1,689	1,126
Cost Recovery Deferral – Conservation (g)	**6,200**	3,511	1,156
Customer Finance Programs (h)	**1,174**	1,250	1,405
	110,452	112,143	109,098
Deductions from Rate Base (average)			
Weather Normalization Reserve (i)	**(1,386)**	3,349	4,931
Other Post-Employment Benefits (j)	**35,822**	27,975	19,066
Customer Security Deposits (k)	**973**	750	846
Accrued Pension Obligation (l)	**4,795**	4,480	4,173
Deferred Income Taxes (m)	**1,899**	2,201	2,188
Excess Earnings (n)	**49**	25	-
Demand Management Incentive Account (o)	**223**	87	143
	42,375	38,867	31,347
Average Rate Base before Allowances	**1,006,063**	952,907	903,849
Rate Base Allowances			
Materials and Supplies	**6,280**	5,619	5,445
Cash Working Capital	**6,739**	6,404	6,526
	13,019	12,023	11,971
Average Rate Base	**$ 1,019,082**	$ 964,930	$ 915,820

(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 $101,448,000 (2014 - $102,584,000) included in the 2015 rate base consists of average deferred pension costs of $101,384,000 (2014 - $102,548,000) and credit facility costs of $64,000 (2014 - $36,000). The Company has included a schedule of these costs in Return 8.

(b) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to 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". The calculation of the 2015 average rate base incorporates $59,000 (2014 - $82,000) related to this deferral account.

(c) In P.U. 13 (2013) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2013, hearing costs related to the 2013/2014 GRA in the amount of $1,250,000. During 2013, the Company deferred $965,000, $285,000 lower than the approved amount, of 2013/2014 GRA hearing costs. Amortization of approximately $322,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $161,000 (2014 - $483,000) which represents the unamortized average balance of the original $965,000. These costs have been fully amortized as of December 31, 2015.

(d) On August 31, 2010 Newfoundland Power submitted an application proposing to defer recovery, until a further Order of the Board, of the amount of $2,363,000 ($1,642,000 after tax) in 2011 to offset the net impact of the expiring amortizations relating to the Municipal Tax Liability, Unrecognized 2005 Unbilled Revenue, Deferred Energy Replacement Costs and the Purchased Power Unit Cost Variance Reserve. This application was approved by the Board in P.U. 30 (2010). P.U. 22 (2011) approved the deferral in 2012 of an additional $2,363,000 ($1,678,000 after tax) related to these expiring amortizations. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Amortization of approximately $1,107,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $553,000 (2014 - $1,661,000) which represents the unamortized average balance of the original $3,320,000. These costs have been fully amortized as of December 31, 2015.

(e) In P.U. 17 (2012) the Board approved the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs. In P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Amortization of approximately $588,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $294,000 (2014 - $883,000) which represents the unamortized average balance of the original deferral. These costs have been fully amortized as of December 31, 2015.

(f) In P.U. 13 (2013) the Board approved the deferral and amortization over three years of amounts related to Newfoundland Power's shortfall in the recovery of revenue requirements for 2013. As a result of this order and updated revenue forecasts subsequently filed by Newfoundland Power in an *Application Filed in Compliance with Order No. P.U. (2013)*, an amount of $3,965,000 ($2,815,000 after tax) has been deferred. Based on a rate implementation date of July 1, 2013, the amortization period had subsequently been updated to 30 months, resulting in amortization for 2013 of $563,000 and amortization of $1,126,000 for 2014 and 2015. The 2015 average rate base includes an addition of

$563,000 (2014 - $1,689,000) which represents the unamortized average balance of the original 2,815,000. These costs have been fully amortized as of December 31, 2015.

(g) In P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan. These costs were fully amortized in 2013. In 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. Included in the calculation of the average rate base for 2015 is $6,200,000 (2014 - $3,511,000) related to this deferral.

(h) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2015 average rate base incorporates $1,174,000 (2014 - $1,250,000) related to these programs.

(i) During 2015, the Weather Normalization reserve was impacted by the following:

Transfer to RSA

i. In 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 $33,000 in 2015 (2014 – $1,712,000 decrease).

Other transfers:

i. $108,000 transfer decrease (2014 – $104,000 decrease) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $4,303,000 transfer decrease (2014 - $71,000 increase) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

Amortization

i. Also in P.U. 13 (2013) the Board approved a three year amortization of the 2011 balance in the Weather Normalization Reserve of $5,020,000 resulting in a decrease to the reserve of $1,673,000 of amortization for 2015 (2014 - $1,673,000 decrease).

The net impact was a net decrease to the reserve of $6,051,000 (2014 - $3,418,000 decrease). The ending balance in this reserve account totaled ($4,411,000) compared to a balance of $1,640,000 at December 31, 2014 (an average of ($1,386,000) for 2015 (2014 - $3,349,000)).

(j) Other Post-Employment Benefits is equal to the difference, at December 31, 2015, between the OPEBs liability of $74,248,000 and the OPEBs asset of $35,040,000. The calculation of the 2015 average rate base of $35,822,000 is equal to the average of the December 31, 2015 net liability of $39,208,000 and the December 31, 2014 net liability of $32,435,000.

(k) 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 2015 average rate base incorporates $973,000 (2014 - $750,000) related to customer security deposits.

(l) The 2015 average rate base calculation incorporates $4,795,000 (2014 - $4,480,000) 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.

(m) In 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 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 2015 average rate base is $656,000 and ($9,695,000) respectively. The remaining balance of the deferred income tax liability in the amount of $10,938,000 relates to capital assets. This results in an average balance for deferred income tax liability of $1,899,000 (2014 - $2,201,000).

(n) In 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.

(o) In P.U. 7 (2014) the Board approved the disposition of the 2013 balance of the Demand Incentive Account of $383,085 (($271,990) after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2014. In P.U. 8 (2015) the Board approved the disposition of the 2014 balance of the Demand Incentive Account of $627,503 ($445,527 after tax) by means of a credit to the Rate Stabilization Account as of March 31, 2015. The 2015 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband. The 2015 average rate base incorporates $223,000 (2014 - $87,000) related to this account.

The net change in the Company's average rate base from 2014 to 2015 can be summarized as follows:

(000's)	2015	2014
Average rate base - opening balance	**$ 964,930**	$ 915,820
Change in average deferred charges and deferred regulatory costs	**(1,615)**	3,200
Average change in:		
Plant in service	**82,016**	76,485
Accumulated depreciation	**(22,497)**	(21,605)
Contributions in aid of construction	**(1,164)**	(1,347)
Weather normalization reserve	**4,735**	1,582
Other post employment benefits	**(7,847)**	(8,909)
Future income taxes	**302**	(13)
Rate base allowances	**996**	52
Other rate base components (net)	**(774)**	(335)
Average rate base - ending balance	**$ 1,019,082**	$ 964,930

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2015 average rate base, and therefore conclude that the 2015 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 2015 was 7.48% (2014 – 7.83%). 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 2015, the return on average rate base is calculated in accordance with the methodology approved in 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 2013 to 2015 is set out in the table below.

	2015	2014	2013
Actual Return on Average Rate Base	**7.48%**	7.83%	8.10%
Upper End of Range set by the Board	**7.68%**	8.06%	8.10%
Lower End of the Range set by the Board	**7.32%**	7.70%	7.74%

The Board approved the Company's rate of return on average rate base of 7.50% in a range of 7.32% to 7.68% for 2015 in P.U. 51 (2014). As noted above, the Company's actual return on average rate base for 2015 was 7.48% which was inside the range set by the Board.

The actual rate of return for 2014 was within the range set by the Board.

The 2013 rate of return on average rate base was outside the range set by the Board (2013 actual return on average rate base of 8.1036%) therefore the Company recorded a regulatory liability and decrease in earnings in the amount of $68,000 ($49,000 after tax). As a result of the revised average rate base we calculated excess earnings of $42,000 ($33,000 after tax). In discussions with the Company they determined the additional excess earnings of $26,000 ($16,000 after tax) reported in Return 13 were immaterial to file a revised return. This represents a benefit to the customer. See 'Regulatory Assets and Liabilities' section of our report for further details.

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 P.U. 13 (2013) the Board reconfirmed its previous position as per P.U. 43 (2009) 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 2015 as reported in Return 24 is as follows:

	2015 Average		**2014**	**2013**
	(000's)	**Percent**	Percent	Percent
Debt	**$559,350**	**54.85%**	54.85%	54.35%
Preferred equity	**8,944**	**0.88%**	0.92%	0.97%
Common equity	**451,501**	**44.27%**	44.23%	44.68%
	$1,019,795	**100.00%**	100.00%	100.00%

Pursuant to 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 2014 test year in Return 26. The embedded cost of debt for 2015 was 6.50% which represents a 49 bps decrease from 2014 embedded cost of debt of 6.99%.

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 Board Order P.U. 13 (2013).

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, 2015 is included on Return 27 of the annual report to the Board. The average common equity for 2015 was $451,501,000 (2014 - $429,174,000). The Company's actual return on average common equity for 2015 was 8.98% (2014 – 9.15%).

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 P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007), P.U. 43(2009) and P.U. 13 (2013).
- recalculated the rate of return on common equity for 2015 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 13 (2013).

In 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 2015 the cost of common equity was 8.80% as per P.U. 13 (2013). The actual return on average common equity for 2015 was 8.98% 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)	**2015**	2014	2013
Net income	**$ 39,314**	$ 37,840	$ 49,920
Income taxes	**10,925**	10,795	(2,877)
Interest on long term debt	**35,020**	36,327	35,123
Interest during construction	**(1,240)**	(1,435)	(893)
Other interest and amortization of debt discount costs	**1,361**	880	1,377
Total	**$ 85,380**	$ 84,407	$ 82,650
Interest on long term debt	**$35,020**	$36,327	$35,123
Other interest and amortization of debt discount costs	**1,361**	880	1,377
Total	**$36,381**	$37,207	$36,500
Interest Coverage (times)	**2.3**	2.3	2.3

The above table shows that the interest coverage did not change from 2014 to 2015.

In 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 2015 is 2.3 times.

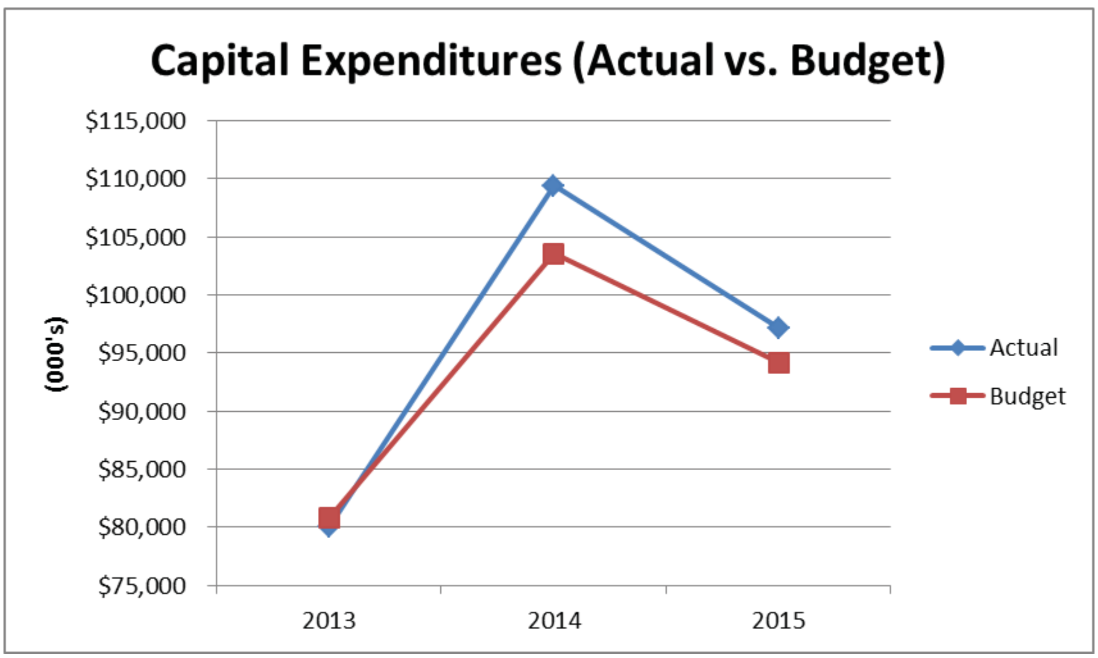
Capital Expenditures

Scope: ***Review the Company's 2015 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 2013 to 2015:

($000's)	**2013**	**2014**	**2015**	**Notes**
Actual	$ 80,013	$ 109,429	$ 97,155	**1**
Budget	$ 80,788	$ 103,572	$ 94,211	
Over (under) budget	(0.96%)	5.66%	3.12%	

Note 1: Total expenditures per the 2015 Capital Budget report includes the carryover amount of $3,772,000 for a total of $100,927,000. The carryover amount is made up of six projects included in the following categories: $180,000 to generation - hydro; $161,000 to substations; $660,000 to transmission; $503,000 to distribution; $1,018,000 to general property; and $1,250,000 to information systems. According to the Company, these expenditures will occur in 2016.



The following table provides a summary of the capital expenditure activity in 2015 as reported in the Company's *"2015 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2015	Total	Prior Years	2015	Total
2015 Capital Projects (1)	$ -	$ 94,211	$ 94,211	$ -	$ 97,155	$ 97,155
2014 Projects Carried to 2015 & Multi Year Projects						
Hydro Plant Production Increase - 2014	1,665	-	1,665	899	931	1,830
Facility Rehabilitation - 2014 (2)	1,610	-	1,610	1,538	410	1,948
Additions due to Load Growth - 2014	5,250	-	5,250	4,385	375	4,760
Rebuild Transmission Lines - 2014	5,099	-	5,099	4,522	342	4,864
Trunk Feeders - 2014 (3)	1,261	-	1,261	1,544	621	2,165
Feeder Additions for Growth - 2014 (4)	1,102	-	1,102	1,360	250	1,610
Hearts Content Plant Refurbishment - Multi Year	5,935	-	5,935	6,164	206	6,370
Rattling Brook Refurbishment - Multi Year	5,000	-	5,000	2,957	69	3,026
	26,922	-	26,922	23,369	3,204	26,573
Grand Total	**$ 26,922**	**$ 94,211**	**$ 121,133**	**$ 23,369**	**$ 100,359**	**$ 123,728**

(1) Approved by Order P.U. 40 (2014).
(2) The Company has noted that the unfavorable variance to budget primarily relates to the poor bedrock conditions discovered during excavation of The Cape Broyle Spillway project, and the work did not get completed as planned in 2014.
(3) The Company has noted that the unfavorable budget variance primarily was a result of additional costs resulted from a design change to permit voltage conversion on the distribution lines being relocated. Additionally, the budget cost of the 2014 Manhole Cover Replacement project was underestimated, which was provided by a third party.
(4) The Company has noted that the unfavorable budget variance primarily was a result of an increase in actual costs over budget relating to three feeder upgrades and additions.

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

($000's)	2015 Budget (1)	2015 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	$ 18,908	$ 17,898	$ (1,010)	$ 280	$ (730)	(3.86%)
Generation - Thermal	216	228	12	-	12	5.56%
Substation	27,728	27,042	(686)	161	(525)	(1.89%)
Transmission	10,830	10,595	(235)	660	425	3.92%
Distribution	44,836	51,587	6,751	503	7,254	16.18%
General property	3,224	2,045	(1,179)	1,018	(161)	(4.99%)
Transportation	2,917	3,080	163	-	163	5.59%
Telecommunications	123	78	(45)	-	(45)	(36.59%)
Information systems	7,501	6,284	(1,217)	1,250	33	0.44%
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	4,100	4,891	791	-	791	19.29%
Total	**$ 121,133**	**$ 123,728**	**$ 2,595**	**$ 3,872**	**$ 6,467**	**5.34%**

1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2 - 2015 actuals include the total expense for projects carried forward from the years 2013 to 2014.
3 - Represents $3,772,000 included in the 2015 budget and an amount of $100,000 from a Multi-year budget, but not yet spent.

As indicated in the table, capital expenditures were greater than the approved budget (including projects carried over from prior years) on a net basis by $2,595,000 and by $6,467,000 (5.34%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 19.29% for the General expenses capitalized category to an under-budget of 36.59% 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	$ 180
Substation Refurbishment and Modernization	161
Transmission Line Rebuild	660
Trunk Feeders	503
Renovations to Company Buildings	1,018
SCADA System Replacement	1,250
Rattling Brook Fisheries Compensation Project	100
Total Carryover	**$ 3,872**

The Company has provided detailed explanations on budget to actual variances in its "2015 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 2015 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 5.66% in 2014 and 3.12% in 2015 resulting in no additional reporting requirements.

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

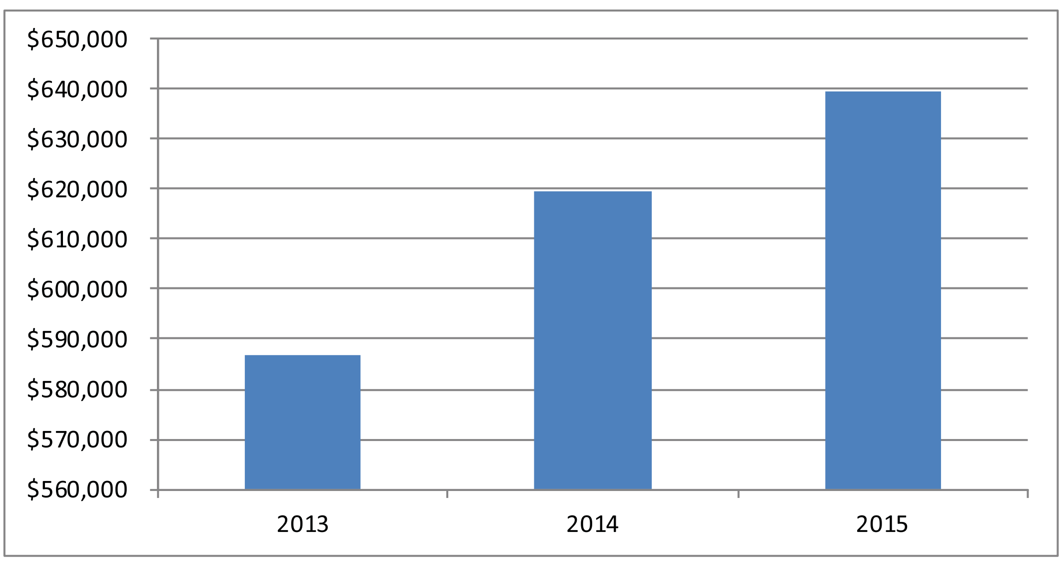
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2015 calendar year.

Revenue

Scope: Review the Company's 2015 revenue in comparison to prior years and follow up on any significant variances.

We have compared the actual revenues for 2013 to 2015 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2013	2014	2015
Residential	$ 367,550	$ 390,614	$ 403,910
General Service			
0-100 kW	81,625	82,080	85,093
110-1000 kVA	83,223	88,789	93,725
Over 1000 kVA	36,961	39,743	38,400
Streetlighting	14,633	15,262	15,541
Discounts forfeited	2,844	3,016	2,962
Revenue from rates	$ 586,836	$ 619,504	$ 639,631
Year over year percentage change	4.57%	5.57%	3.25%



The above graph demonstrates that the Company has seen a 3.25% increase in revenue from rates in 2015 as compared to 2014. The increase primarily relates to an increase in customer energy rates effective July 1, 2015 related to the Board's approval of an interim rate increase in the wholesale electricity rate charged by Newfoundland and Labrador Hydro to the Company. The remaining increase in revenue reflects higher electricity sales. There was a 0.98% increase in the overall demand in GWh for 2015. For residential sales there was an increase of 3.40% in 2015 revenue from 2014. GWh sold in this category increased by 1.14%, and the number of residential customers increased by 1.17%.

The comparison by rate class of 2015 actual revenues to 2015 budget is as follows:

($000's)	2014	2015	2015 Plan	Actual - Plan Variance	%
Residential	$ 390,614	$ 403,910	$ 397,880	$ 6,030	1.52%
General Service					
0-100 kW	82,080	85,093	83,020	2,073	2.50%
110-1000 kVA	88,789	93,725	89,857	3,868	4.30%
Over 1000 kVA	39,743	38,400	40,521	(2,121)	(5.23%)
Streetlighting	15,262	15,541	15,333	208	1.36%
Discounts forfeited	3,016	2,962	2,940	22	0.75%
Total revenue from rates	$ 619,504	$ 639,631	$ 629,551	$ 10,080	1.60%

We have also compared the 2015 budget energy sales in GWh to the actual sold in 2015:

	2014	2015	2015 Plan	Actual - Plan Variance	%
Residential	3,613.1	3,654.2	3,680.6	(26.4)	(0.72%)
General Service					
0-100 kW	782.8	792.4	795.2	(2.8)	(0.35%)
110-1000 kVA	965.1	998.3	973.1	25.2	2.59%
Over 1000 kVA	505.6	479.5	516.3	(36.8)	(7.13%)
Streetlighting	31.9	32.2	32.0	0.2	0.63%
Total revenue from rates	5,898.5	5,956.6	5,997.2	(40.6)	(0.68%)

Actual 2015 revenue from rates was higher than 2015 Plan with an overall increase in actual sales of $10,080,000 (1.60%) from the 2015 Plan. There was a 0.68% decrease in GWh sold in 2015 compared to 2015 Plan. The largest variances in revenue can be seen in the Residential and 110-1000 KVA classes where revenues increase by $6,030,000 (1.52%) and $3,868,000 (4.30%) respectively, and they are offset partially by over 1000 kVA class where actual revenues decreased by $2,121,000 (5.23%).

Operating and General Expenses

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

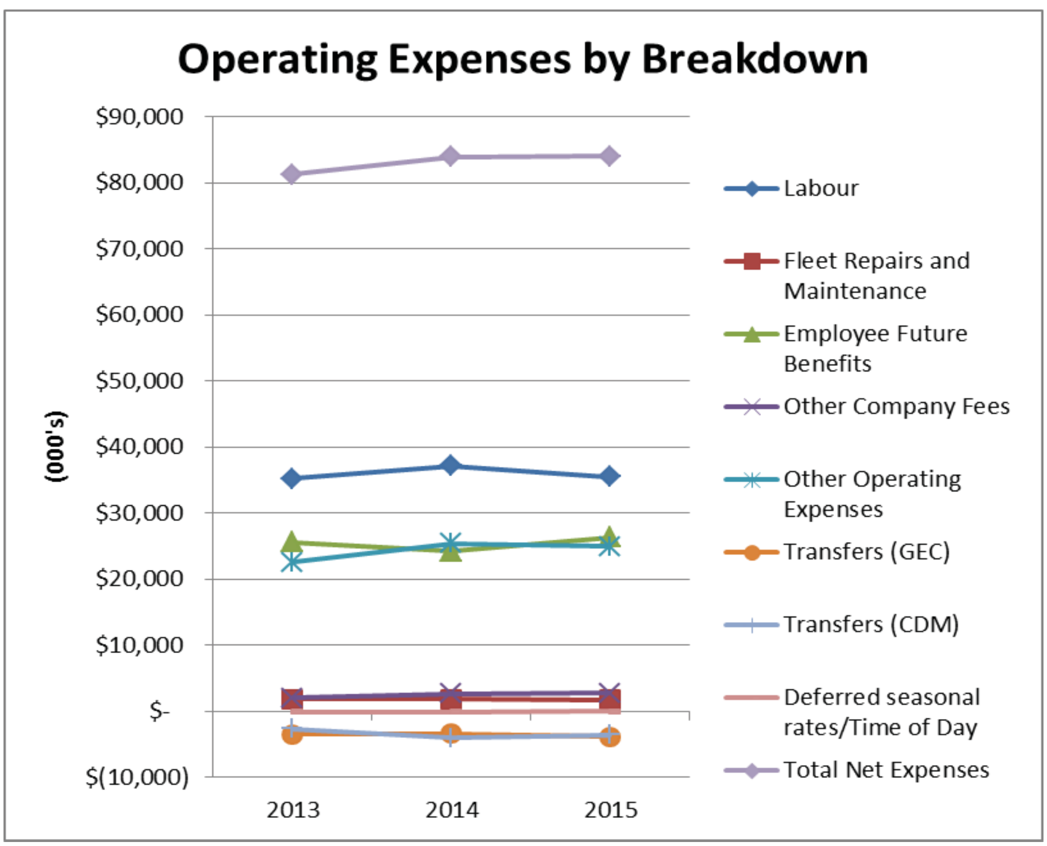
(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Labour	$ 36,485	$ 37,871	$ 35,918	$ (1,386)
Reclass OPEB labour cost	(969)	(658)	(663)	(311)
Total Labour	35,516	37,213	35,255	(1,697)
Vehicle expense	1,786	1,901	1,881	(115)
Operating materials	1,583	1,857	1,568	(274)
Inter-company charges	1,560	1,710	1,184	(150)
Plants, Subs, System Oper & Bldgs	2,367	2,312	2,153	55
Travel	1,052	1,318	1,297	(266)
Tools and clothing allowance	1,130	1,192	1,141	(62)
Miscellaneous	1,765	1,970	1,751	(205)
Conservation	2,466	1,762	1,250	704
Taxes and assessments	1,123	1,040	1,011	83
Uncollectible bills	1,313	1,490	897	(177)
Insurance	1,260	1,243	1,197	17
Severance & other employee costs	72	58	84	14
Education, training, employee fees	298	310	392	(12)
Trustee and directors' fees	462	431	397	31
Other company fees	2,757	2,650	2,024	107
Stationary & copying	230	266	308	(36)
Equipment rental/maintenance	746	769	677	(23)
Communications	3,184	3,220	3,074	(36)
Advertising	1,251	1,444	1,113	(193)
Vegetation management	1,766	1,789	1,993	(23)
Computing equipment & software	1,058	915	799	143
Total Other	29,229	29,647	26,191	(418)
Pension & early retirement program	17,702	13,276	14,744	4,426
OPEB's	8,653	10,968	10,880	(2,315)
Total employee future benefits	26,355	24,244	25,624	2,111
Total gross expenses	91,100	91,104	87,070	(4)
Transfers (GEC)	(3,809)	(3,399)	(3,415)	(410)
CDM amortization	1,053	420	339	633
Deferred CDM program costs	(4,611)	(4,436)	(2,937)	(175)
Deferred seasonal rates/TOD	(9)	(39)	(71)	30
Deferred regulatory costs	322	322	322	-
Total net expenses	$ 84,046	$ 83,972	$ 81,308	$ 74

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2013, 2014 and 2015 Actual.

Overall, net operating expenses were relatively flat as there was only an increase of $74,000 from 2014 to 2015. 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 2015 are unreasonable.

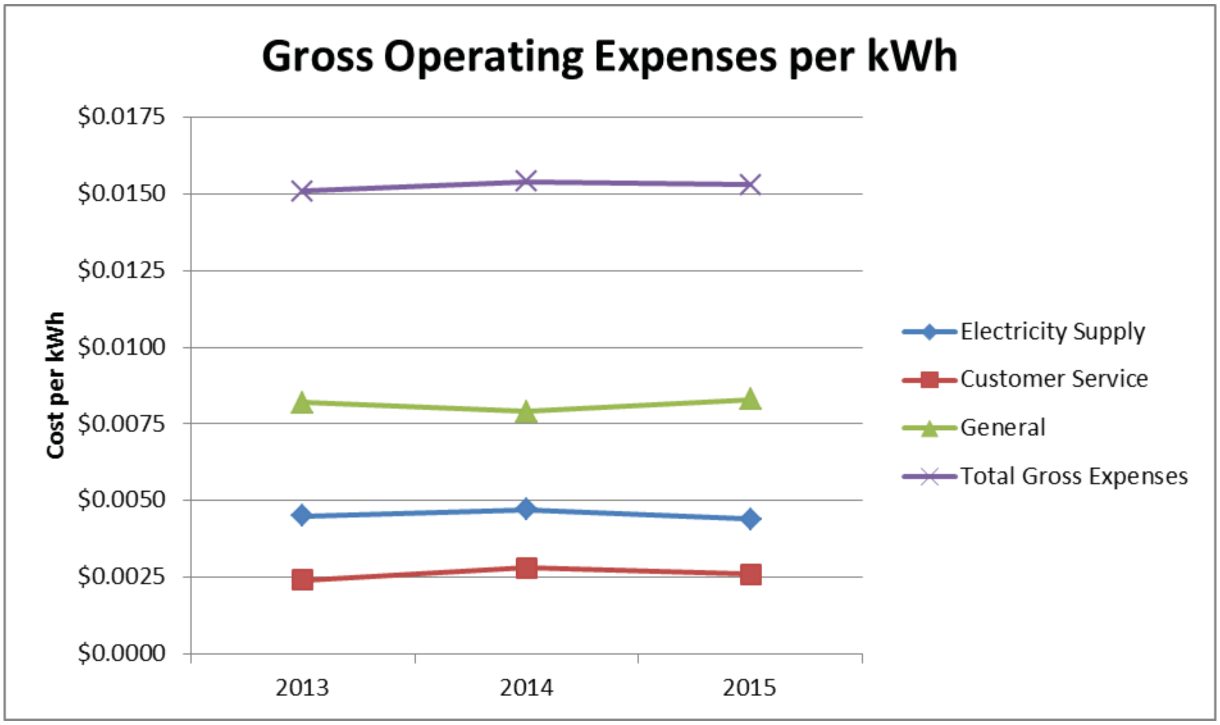
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2013 to 2015.

	Actual		
(000's)	2013	2014	2015
Labour	$ 35,255	$ 37,213	$ 35,516
Fleet Repairs and Maintenance	1,881	1,901	1,786
Employee Future Benefits	25,624	24,244	26,355
Other Company Fees	2,024	2,650	2,757
Other Operating Expenses	22,608	25,418	25,008
Transfers (GEC)	(3,415)	(3,399)	(3,809)
Transfers (CDM)	(2,598)	(4,016)	(3,558)
Deferred seasonal rates/Time of Day	(71)	(39)	(9)
Total Net Expenses	$ 81,308	$ 83,972	$ 84,046



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2013 to 2015 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
2013	5,763,300	$ 26,072	$ 0.0045	$ 14,009	$ 0.0024	$ 46,989	$ 0.0082	$ 87,070	$ 0.0151
2014	5,898,500	$ 27,817	$ 0.0047	$ 16,478	$ 0.0028	$ 46,809	$ 0.0079	$ 91,104	$ 0.0154
2015	5,956,600	$ 26,191	$ 0.0044	$ 15,474	$ 0.0026	$ 49,435	$ 0.0083	$ 91,100	$ 0.0153



The table and graph show that total gross expenses per kWh have decreased by approximately 0.6% compared to 2014.

There was an increase in General Costs of $2.6 million but those costs were offset by decreases in Electricity Supply Costs and Customer Service Costs of $1.6 million and $1.0 million respectively. 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 2013 to 2015 (including 2015 plan) is as follows:

	Actual 2015	Plan 2015	Actual 2014	Actual 2013	Actual - Plan	Actual 2015-2014
Executive Group	**6.0**	**6.0**	5.8	6.0	0.0	0.2
Corporate Office	**20.7**	**22.0**	22.3	21.0	(1.3)	(1.6)
Finance	**93.5**	**91.4**	90.9	89.1	2.1	2.6
Egineering and Operations	**418.5**	**434.5**	424.4	422.1	(16.0)	(5.9)
Customer Relations	**68.0**	**67.9**	72.9	62.0	0.1	(4.9)
	606.7	**621.8**	616.3	600.2	(15.1)	(9.6)
Temporary employees	**46.3**	**50.3**	48.5	55.6	(4.0)	(2.2)
Total	**653.0**	**672.1**	664.8	655.8	(19.1)	(11.8)

The overall number of FTE's in 2015 compared to 2014 decreased by 11.8. The budgeted number of FTE's in the 2015 Plan was 672.1 versus actual of 653.0. The variances between 2015, 2015 Plan and 2014 are the result of the following:

- The Corporate Office is lower than 2014 and 2015 plan primarily due to the timing of retirements and leaves of absence.
- Finance is higher than 2014 due primarily to increased resources required for information systems and infrastructure support including supervisory control and data acquisition (SCADA) and geographic information systems (GIS).
- Engineering and operations is lower than Plan 2015 and 2014 actual due primarily to timing of retirements and leaves of absence, labour efficiencies and transfers of employees to other departments.
- Customer Relations is lower than 2014 actual due primarily to timing of retirements and leaves of absence partially offset by the expansion of customer energy conservation programming
- Temporary Employees are lower than both 2014 and Plan 2015 due primarily to labour efficiencies including the implementation of the Automated Meter Reading (AMR) strategy and a shift of temporary positions to fulltime.

An analysis of salaries and wages by type of labour and by function from 2013 to 2015 is as follows:

(000's)	**Actual 2015**	Actual 2014	Actual 2013	**Variance 2015-2014**
Type				
Internal labour	**$ 63,330**	$ 62,275	$ 59,784	$ 1,055
Overtime	**5,117**	6,968	5,228	(1,851)
	68,447	69,243	65,012	(796)
Contractors	**15,232**	18,286	13,613	(3,054)
	$ 83,679	$ 87,529	$ 78,625	$ (3,850)
Function				
Operating	**$ 36,485**	$ 37,871	$ 35,918	$ (1,386)
Capital and miscellaneous	**47,194**	49,658	42,707	(2,464)
Total	**$ 83,679**	$ 87,529	$ 78,625	$ (3,850)
Year over year percentage change	-4.40%	11.32%	6.54%	

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 2015 were $3,850,000 (-4.40%) lower than 2014.

Internal labour costs in 2015 were higher than 2014 by 1.70% primarily due to normal salary increases partially offset by a reduction in full time equivalents.

Overtime in 2015 was lower than 2014 as 2014 included increased labour costs required for restoration and customer service response following the loss of generation supply from Hydro, increased peak load management, inclement weather conditions and a higher number of trouble calls.

Contract labour was lower than 2014 due primarily to decreased distribution work associated with the Bell Island Cable replacement.

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 2013 to 2015 are included in the table below:

Salary Cost Per FTE

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Total reported internal labour costs	**$ 63,330**	$ 62,275	$ 59,784	$ 1,055
Benefit costs (net)	**(7,559)**	(7,448)	(7,502)	(111)
Other adjustments	**(605)**	(646)	(571)	41
Base salary costs	**55,166**	54,181	51,711	985
Less: executive compensation	**(1,750)**	(1,932)	(1,893)	182
Base salary costs (excluding executive)	**$ 53,416**	$ 52,249	$ 49,818	$ 1,167
FTE's (including executive members)	**653.0**	664.8	655.8	
FTE's (excluding executive members)	**649.0**	661.0	651.8	
Average salary per FTE	**84,481**	81,500	78,952	
% increase	**3.66%**	3.36%	3.71%	
Average salary per FTE (excluding executive members)	**82,305**	79,045	76,531	
% increase	**4.12%**	3.42%	3.68%	

The above analysis indicates that for 2015 the rate of increase in average salary per FTE has been fairly consistent from 2013 to 2015.

During 2014, the Company negotiated a new collective agreement with its union that was ratified in 2015.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2013 to 2015 and the targets set for 2015:

Measure	Target 2015	Actual 2015	Actual 2014	Actual 2013
Controllable Operating Costs/Customer	**$231.60**	$219.80	$223.90	$217.60
Earnings	**37.7m**	38.8m	37.3m	36.5m
Reliability - Duration of Outages (SAIDI)	**2.30**	2.36	2.44	2.23
Customer Satisfaction - % Satisfied	**84.7%**	86.1%	83.5%	85.9%
Injury Frequency Rate	**0.69**	0.18	0.51	0.52
Regulatory Performance	**Subjective**	140%	150%	150%

2015 STI results were adjusted to remove the impact of the loss of supply from Hydro in March. In 2013, First Call Resolution was replaced with Regulatory Performance. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or cost based analyses. For 2015, the key determinants of the result of 140% were as follows: (i) the company's participation in the Board's investigation into system reliability initiated in 2014. Newfoundland Power played an active role in both phases of the Board's Investigation in 2015. For Phase One this included (1) responding to the Board in relation to the conclusions and recommendations of the Board's consultant, (2) testifying before the Board in the Phase One hearing, and (3) final written submissions. For Phase Two, Newfoundland Power engaged a consultant and issued requests for information to better understand reliability once the Muskrat Falls project is integrated into the island interconnected system. (ii) the 2016 capital budget application, and (iii) the Company's efforts in participating in Newfoundland & Labrador Hydro's Amended General Rate Application and the Newfoundland Power General Rate Application.

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 2015 is established as a percentage of base pay for the three employee groups. For 2015, measures relating to 'controllable operating costs/customer', 'earnings', 'safety', 'regulatory performance' and 'customer satisfaction' metrics were met, however "SAIDI" metrics fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2013 to 2015:

	Target 2015	Actual 2015	Target 2014	Actual 2014	Target 2013	Actual 2013
President	50%	64.90%	40-50%	64%	50%	70%
Executive	40%	51.90%	35%	44.8%	35-40%	52.1%
Directors	15%	19.60%	15%	19.2%	15%	21.2%

STI actual payout rates for 'President', 'Executive' and 'Director' employee groups are higher than in the prior year and each payout rate exceeded target consistent with 2014 and 2013.

In dollar terms, the STI payouts for 2013 to 2015 are as follows:

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
President	**$ 227,000**	$ 360,000	$ 294,000	$ (133,000)
Executive	**401,000**	312,000	404,000	89,000
Directors	**342,200**	320,300	302,000	21,900
Total	**$ 970,200**	$ 992,300	$ 1,000,000	$ (22,100)
Year over Year % change	-2.23%	-0.77%	7.3%	

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In 2015, the non-regulated portion (before tax adjustment) was $224,170 (2014 - $272,588).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2013 to 2015.

	Base Salary	Short Term Incentive	Other	Total
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**
2014				
Total executive group	$ 1,268,257	$ 672,000	$ 131,845	$ 2,072,102
Average per executive (4)	**$ 317,064**	**$ 168,000**	**$ 32,961**	**$ 518,026**
2013				
Total executive group	$ 1,195,019	$ 698,000	$ 126,744	$ 2,019,763
Average per executive (4)	**$ 298,755**	**$ 174,500**	**$ 31,686**	**$ 504,941**
% Average decrease 2015 vs 2014	-11.53%	-6.55%	-19.42%	-10.42%

Base salary for the executive group in 2015 decreased from 2014 primarily due to the fact that there were salary decreases for the newly appointed President & CEO as at August 1, 2014 and the Vice President, Customer Operations & Engineering as at October 29, 2014. Also, the executive salary information provided by Newfoundland Power for the 2014 year included the management salary of the Vice President of Customer Operations & Engineering who was promoted to the role as at October 29, 2014. Base salaries have been agreed to the 2016 Board of Directors' minutes, and STI payouts have been agreed to the 2016 Board of Directors' minutes.

Company Pension Plan

For 2015, we reviewed the accounts supporting the gross charge of $17,702,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2013 to 2015:

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Pension expense per actuary	**$15,332,000**	$ 11,084,000	$ 12,744,000	$ 4,248,000
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**562,000**	568,000	560,000	(6,000)
Group RRSP @ 1.5%	**384,000**	422,000	440,000	(38,000)
Individual RRSP's	**1,421,000**	1,211,000	1,013,000	210,000
Less: Refunds (net of other expenses)	**3,000**	(9,000)	(13,000)	12,000
Total	**$17,702,000**	$ 13,276,000	$ 14,744,000	$ 4,426,000
Year over year percentage change	**33.34%**	(9.96%)	14.33%	

Overall, pension expense for 2015 is higher than 2014 primarily due to a lower discount rate at December 31, 2014, which is used to determine the pension obligation for 2015.

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 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 1.06% in 2015.

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 17.3% 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 $172,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2014 was primarily the result of wage increases and new hires in the year, which was partially offset by retirements and terminations (35 retirements in 2015). The net increase for RRSP expenditures in 2015 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 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 2013 to 2015 are as follows:

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Accrued OPEBs	**$ 6,055**	$ 8,038	$ 7,957	$ (1,983)
Amortization of transitional balance	**3,504**	3,504	3,504	-
Amount capitalized	**(906)**	(574)	(581)	(332)
Total	**$ 8,653**	$ 10,968	$ 10,880	$ (2,315)

According to the company, the lower OPEBs costs in 2015 reflect a reduction in claims cost experience under the plan as determined in the actuarial report.

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 2013 to 2015 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2015 and investigated any unusual items;
- vouched a sample of transactions for 2015 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 2013 to 2015 for charges to and from Newfoundland Power Inc.:

	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges from related companies				
Regulated	**$ 208,781**	$ 311,536	$ 203,300	$ (102,755)
Non-Regulated	**1,672,009**	1,990,723	1,467,175	(318,714)
Total	**$ 1,880,790**	$ 2,302,259	$ 1,670,475	$ (421,469)
Charges to related companies	**$ 229,125**	$ 336,758	$ 506,639	$ (107,633)

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 2015.

- Fortis Inc. estimated its net pool of operating expenses for 2015 in Q4 2014 as part of its annual business planning process 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 evenly based upon 25% of the estimated annual amount.
- For the fourth quarter, a true-up calculation is completed to reflect actual expenses incurred during the year. Fortic Inc. used the average actual assets for the first 3 quarters and forecast 4th quarter in this calculation. Since regulated expenses are fairly consistent from month to month, the estimate in the 4th quarter expenditures had a minimal impact.

During the fourth quarter of 2015, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $1,560,000 and are summarized as follows:

2015 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$944,000	Non-regulated
Director Fees	114,000	Non-regulated
Consulting and Legal fees	137,000	Non-regulated
Trustee Agent Fees	35,000	Regulated
Audit and Other Fees	33,000	Non-regulated
Public Reporting Costs	40,000	Non-regulated
Annual Meeting Expenses	37,000	Non-regulated
Travel (Board and Other)	52,000	Non-regulated
Insurance (D&O)	21,000	Non-regulated
Other Costs	147,000	Non-regulated
	1,560,000	
Less amounts previously billed:		
Q1 2015	453,000	
Q2 2015	453,000	
Q3 2015	453,000	
Q4 2015 balance owing	$ 201,000	

For 2015, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 5.65%, down from 7.43% in 2014.

As detailed above, trustee agent fees for $35,000 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 2013 to 2015 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 35,000**	$ 48,000	$ 53,000	$ (13,000)
Miscellaneous	**24,472**	128,593	14,185	(104,121)
Staff Charges	**19,756**	-	-	19,756
	$ 79,228	$ 176,593	$ 67,185	$ (97,365)
Year over year percentage change	**(55.14%)**	162.85%	2.79%	
Charges to Fortis Inc.				
Printing and stationery	**$ 2,191**	$ 76	$ -	$ 2,115
Postage and couriers	**19,468**	25,704	24,565	(6,236)
Staff charges	**44,430**	43,667	97,979	763
Staff charges - insurance	**4,639**	38,527	183,267	(33,888)
IS Charges	**-**	-	309	-
Pole removal and installation	**-**	769	572	(769)
Miscellaneous	**7,855**	64,713	6,090	(56,858)
	$ 78,583	$ 173,456	$ 312,782	$ (94,873)
Year over year percentage change	**(54.70%)**	(44.54%)	(29.91%)	

The most significant fluctuation from our analysis of regulated charges from Fortis Inc. is within the miscellaneous account of a decrease of $104, 121. This is primarily due to the transfer of an unused vacation accrual of $108,844 being transferred to Fortis Inc. when the former CEO moved from Newfoundland Power to Fortis from 2014.

The most significant fluctuation from our analysis of regulated charges to Fortis Inc. is a $56,858 decreases in miscellaneous. This is primarily a result of 2014 actual reflecting the sale of the former CEO's vehicle for $53,089 to Fortis Inc.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2013 to 2015:

(Non-Regulated)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges from Fortis Inc.				
Director's fees and travel	**166,000**	373,000	185,000	$ (207,000)
Annual and quarterly reports	**73,000**	98,000	90,000	$ (25,000)
Staff charges	**944,000**	849,000	558,000	$ 95,000
Miscellaneous	**489,009**	663,602	634,175	$ (174,593)
	$ 1,672,009	$ 1,983,602	$ 1,467,175	$ (311,593)
Year over year percentage change	**(15.71%)**	35.20%	(6.50%)	

Director’s fees and travel decreased by $207,000, primarily due to the decrease in Newfoundland Power’s allocation of director’s fees from Fortis Inc., mainly due to the impact of share price depreciation for 2015 compared to the share price appreciation for 2014.

Miscellaneous charges decreased by $174,593 reflect the difference in stock option expenses which were $321,000 in 2014 versus $147,000 in 2015.

The following table provides a summary and comparison of the other intercompany transactions for 2013 to 2015:

Intercompany Transactions (Other)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges to Fortis Properties				
Staff charges	**$ 23,569**	$ 12,108	$ -	$ 11,461
Staff charges - insurance	**21,796**	23,753	30,894	(1,957)
Stationary costs	**-**	288	352	(288)
Miscellaneous	**500**	790	2,770	(290)
	$ 45,865	$ 36,939	$ 34,016	$ 8,926
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 3,113**	$ 34,048	$ 52,961	$ (30,935)
Miscellaneous	**48,885**	1,664	1,636	47,221
	$ 51,998	$ 35,712	$ 54,597	$ 16,286
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 3,620**	$ 3,116	$ 4,091	$ 504
Staff charges	**5,666**	4,986	16,587	680
IS charges	**4,065**	4,208	4,080	(143)
Miscellaneous	**390**	380	370	10
	$ 13,741	$ 12,690	$ 25,128	$ 1,051
Charges to Maritime Electric				
Staff charges	**$ 6,541**	$ 3,813	$ 6,976	$ 2,728
Staff charges - insurance	**934**	1,444	1,954	(510)
IS charges	**3,048**	2,945	2,856	103
Miscellaneous	**530**	510	573	20
	$ 11,053	$ 8,712	$ 12,359	$ 2,341
Charges from Maritime Electric				
Staff charges	**$ -**	$ 34,372	$ -	$ (34,372)
Miscellaneous	**250**	-	5,614	250
	$ 250	$ 34,372	$ 5,614	$ (34,122)
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 182**	$ 13,973	$ 4,647	$ (13,791)
Charges to Central Hudson Gas & Electric				
Staff charges - insurance	**$ -**	$ -	$ 6,702	$ -
Charges to Fortis US Energy Corp				
Staff charges - insurance	**$ -**	$ -	$ 74	$ -

Intercompany Transactions (Other) Cont'd.	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 20,779**	$ -	$ -	$ 20,779
Staff charges - insurance	**-**	648	6,177	(648)
	$ 20,779	$ 648	$ 6,177	$ 20,131
Charges to FortisAlberta Inc.				
Staff charges - insurance	**$ 39**	$ 76	$ 3,359	$ (37)
Miscellaneous	**4,260**	13,280	3,650	(9,020)
	$ 4,299	$ 13,356	$ 7,009	$ (9,057)
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 49,452**	$ 37,611	$ 41,411	$ 11,841
Charges to FortisBC Inc.				
IS charges	**10,363**	11,781	11,424	(1,418)
Staff charges - insurance	**39**	-	2,768	39
Miscellaneous	**2,410**	2,342	2,363	68
	$ 12,812	$ 14,123	$ 16,555	$ (1,311)
Charges from FortisBC Inc.				
Miscellaneous	**$ 3,822**	$ 3,322	$ 8,740	$ 500
Charges to Fortis BC Holdings				
Staff charges - insurance	**$ -**	$ 648	$ 2,882	$ (648)
Miscellaneous	**6,780**	6,360	6,290	420
	$ 6,780	$ 7,008	$ 9,172	$ (228)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 22,219**	$ 27,113	$ 54,492	$ (4,894)
Staff charges - insurance	**-**	120	11,048	(120)
Miscellaneous	**-**	-	1,400	-
	$ 22,219	$ 27,233	$ 66,940	$ (5,014)
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ 23,849**	$ 17,074	$ 21,106	$ 6,775
Charges to Fortis Turks and Caicos				
Staff charges	**$ 12,271**	$ 42,391	$ -	$ (30,120)
Staff charges - insurance	**-**	162	9,477	(162)
Miscellaneous	**723**	40	248	683
	$ 12,994	$ 42,593	$ 9,725	$ (29,599)

The most significant fluctuations from our analysis of other intercompany charges for 2015 compared to 2014 are as follows:

- Hotel/Banquet facilities and meal charges decreased by $30,935 from Fortis Properties, which is related to the 2014 Newfoundland Power's Christmas dinner and dance held at the Delta Hotel in St. John's.
- Miscellaneous charges from Fortis Properties increased by $47,221, which reflects the charges associated with a Fortis Properties employee's secondment to Newfoundland Power's Corporate Communication department in 2015.
- Staff charges from Maritime Electric decreased by $34,372, due to 2014 required labour and travel expenses for line crews who assisted in power restoration efforts in January 2014.
- Staff charges increased by $20,779 to Belize Electric Company Ltd. relating to two Newfoundland Power personnel who supplied audit, engineering and technological consultation services to Belize Electric.
- Staff Charges to Fortis Turks and Caicos decreased by $30,120, which is related to two Newfoundland Power personnel supplied services to Fortis Turks and Caicos during 2015 versus five during 2014.

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.	$ 10,000,000	April. 20, 2015	April. 30, 2015	2.450%	$ 6,712
Fortis Inc.	5,000,000	May. 20, 2015	May. 27, 2015	2.450%	2,349
Fortis Inc.	10,500,000	October. 20, 2015	October. 28, 2015	1.188%	1,543
Fortis Inc.	10,000,000	November. 20, 2015	December. 8, 2015	1.216%	5,129
	$ 35,500,000				$ 15,733

[1] - Interest charged by Fortis is charged at a discount price and includes a stamp fee.

The interest rates charged on each of the loans above were lower than what would have been charged under the Company's debt facilities. In April and May, the Company had borrowed the maximum of $100 million from their committed credit facility which meant that any further borrowings would have been done from their demand facility at an interest rate of 2.85%, which were provided by Fortis Inc. at an interest which was 0.40% lower. Likewise, the interest rates which would have been charged under the Committed Credit facility for each of the loans in October and November would have been 0.412% and 0.414% higher respectively.

In Order 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 2015. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2015.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2013/14

General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2015 and noted some exceptions. Staff charges relating to routine insurance matters (e.g.; coverage queries, damage claims, arranging for insurance certificates) are based on the recovery of fully distributed costs (hourly rate plus 70% markup). The Company noted that they believe this policy to be accordance with Section 6.5 of the Inter-Affiliate Code of Conduct (May 2011) submitted to the Board on June 10, 2011. These charges were further investigated to determine the impact of using a lower rate. It was determined that had the Company charged $108 per hour rather than the fully distributed cost, an additional $12,000 in staff insurance charges to related parties would result in 2015.

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 2015 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Other company fees				
Other company fees	$ 1,601	$ 1,791	$ 1,648	$ (190)
Regulatory hearing costs	1,156	859	376	297
	$ 2,757	$ 2,650	$ 2,024	$ 107
Year over year percentage change	4.0%	30.9%	-18.6%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 322	$ 322	$ 322	$ -
Year over year percentage change	0.0%	0.0%	27.3%	

Total company fee costs for 2015 were higher than 2014 actual by $107,000. These costs were higher than 2014 due primarily to increased regulatory activity partially offset by lower consultant costs for customer energy conservation programming in 2015. 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 2013 to 2015 is as follows:

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Miscellaneous	**$ 967**	$ 1,164	$ 1,048	$ (197)
Cafeteria and lunchroom Supplies	**84**	92	95	(8)
Promotional items	**152**	120	119	32
Computer Software	**2**	5	5	(3)
Damage claims	**301**	259	241	42
Community relations activities	**3**	1	11	2
Donations and charitable advertising	**188**	263	172	(75)
Books, magazines and subscriptions	**35**	33	33	2
Misc. lease payments	**33**	33	27	-
Total miscellaneous expenses	**$ 1,765**	$ 1,970	$ 1,751	$ (205)
Year over year percentage change	**-10.41%**	12.51%	7.82%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2014 to 2015 these expenses have decreased by 10.41% overall, primarily due to the fact 2014 included increased customer energy conservation programming materials and higher non-regulated donations.

Our procedures in this expense category for 2015 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 2015 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2015 Conservation and Demand Management Report with the Board. This report provided a summary of 2015 CDM activities and costs as well as the outlook for 2015.

In 2015, the Company and Newfoundland and Labrador Utilities completed work on an updated Conservation Potential Study ("CPS") for Newfoundland and Labrador. The primary outcomes of this CPS were the identification of cost-effective energy and demand reduction measures, general parameters for program development, and quantification of achievable energy savings potential by sector and end-use.

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 CPS through in-depth local market research and program cost benefit analysis.

Total CDM costs in 2015 totaled $5,736,000 compared to $5,588,000 in 2014, a $148,000 increase. There was an increase in costs for Small Technologies and the Business Efficiency Program but these increases were partially offset by a decrease in Windows costs as the Windows program ended in December 2014.

In 2015, $4,611,000 ($3,274,000 after tax) in CDM costs were deferred to be amortized over 7 years as per P.U. (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 2015 and 2014.

(000's)	Actual 2015	Actual 2014	Actual 2013	Variance 2015-2014
Vehicle expense	1,786	1,901	1,881	(115)
Operating materials	1,583	1,857	1,568	(274)
Plants, Subs, System Oper & Bldgs	2,367	2,312	2,153	55
Travel	1,052	1,318	1,297	(266)
Tools and clothing allowance	1,130	1,192	1,141	(62)
Conservation	2,466	1,762	1,250	704
Taxes and assessments	1,123	1,040	1,011	83
Uncollectible bills	1,313	1,490	897	(177)
Severance and other employee costs	72	58	84	14
Insurance	1,260	1,243	1,197	17
Education, training, employee fees	298	310	392	(12)
Trustee and directors' fees	462	431	397	31
Stationary & copying	230	266	308	(36)
Equipment rental/maintenance	746	769	677	(23)
Communications	3,184	3,220	3,074	(36)
Advertising	1,251	1,444	1,113	(193)
Vegetation management	1,766	1,789	1,993	(23)
Computing equipment & software	1,058	915	799	143
Transfers (GEC)	(3,809)	(3,399)	(3,415)	(410)
CDM amortization	1,053	420	339	633
Deferred seasonal rates/TOD	(9)	(39)	(71)	30

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

- Vehicle operating costs for 2015 were lower than 2014 primarily due to lower fuel prices
- Operating materials were lower than 2014 primarily due to higher maintenance costs related to the Topsail penstock repairs in 2014
- Travel was lower than 2014 due to reduced employee travel in 2015 and lower employee relocation costs
- Conservation costs increased from 2014 due to increased customer energy conservation incentives
- Uncollectible bills costs were lower than 2014 actual as weather conditions in the winter of 2014 contributed to the increase in uncollectable bills in that year.
- Advertising costs were lower than 2014 due primarily to lower advertising costs for customer energy conservation programming.
- Computing equipment & software costs increased from 2014 primarily due to increases in 3rd party software licensing and maintenance costs associated with the Company's information systems.
- Transfers to General Expenses Capitalized (GEC) for 2015 were higher than 2014 due primarily to higher pension costs.

- Conservation and Demand Management (CDM) amortization has increased from 2014. In 2013, the Board approved the deferred recovery, over a 7 year period, of annual costs associated with expansion of customer energy conservation programming. Amortization of this deferral commenced in 2014 and is higher in 2015 due to the inclusion of the second year of deferred customer energy conservation programming costs.

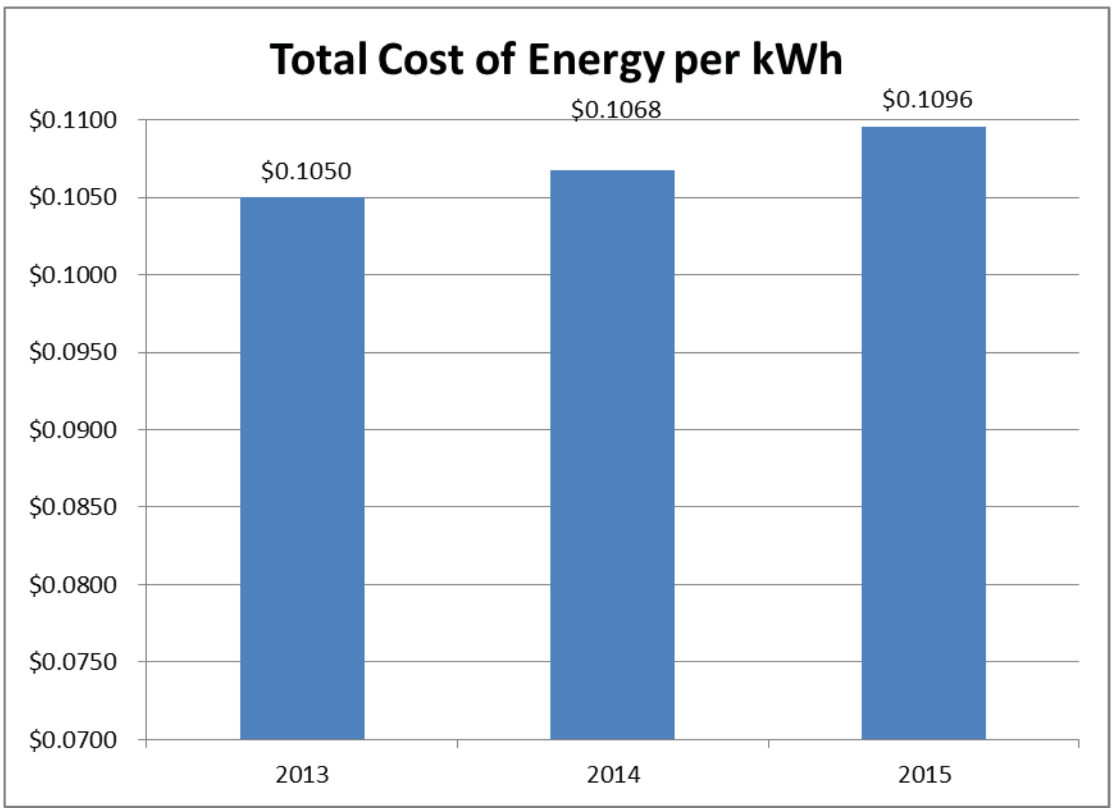
Other Costs

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 2013 to 2015:

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
2013	5,763,300	$ 81,308	$ 390,210	$ (768)	$ 51,300	$ 36,034	$ (2,877)	$ 49,920	$ 605,127	$ 0.1050
2014	5,898,500	$ 83,972	$ 402,843	$ 3,990	$ 53,882	$ 36,450	$ 10,795	$ 37,840	$ 629,772	$ 0.1068
2015	5,956,600	$ 84,046	$ 422,095	$ 3,990	$ 56,720	$ 35,724	$ 10,925	$ 39,314	$ 652,814	$ 0.1096



Purchased Power

We have reviewed the Company's purchased power expense for 2015 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 $19.3 million, from $402.8 million in 2014 to $422.1 million in 2015. According to the Company, the increase resulted primarily from electricity sales growth and the interim rate increase in the wholesale electricity rate charged by Hydro to Newfoundland Power effective July 1, 2015. These increases were partially offset by a reduction in purchased power expense due to higher generation than water inflows at the Company's hydroelectric generating facilities.

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, 2010 and assessed the reasonableness of depreciation expense.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. The study for plant in service as of December 31, 2010 was completed in 2011. The study was included in the 2013-2014 General Rate Application by the Company and was approved in P.U. 13 (2013), including the approval of the accumulated depreciation reserve variance of $2.6 million to be amortized over the average remaining service life of the related assets. The depreciation rates from the 2010 depreciation study, including the amortization of the accumulated depreciation reserve, were implemented effective January 1, 2013.

Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method in its 2010 depreciation study as this method provides for a better match of depreciation expense and loss in service.

The objective of our procedures in this section was to ensure that the 2015 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2010 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 2015; and,
- assessed the overall reasonableness of the depreciation for 2015.

Amortization expense for 2015 is $56,720,000 as compared to $53,882,000 for 2014, representing a 5.27% increase. The 2015 and 2014 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)	2015	2014	Variance 2015-2014	%
Depreciation and amortization as reported	$ 56,720	$ 53,882	$ 2,838	**5.3%**
Less: Tax on Cost of Removal (1)	(4,869)	(4,594)	(275)	**6.0%**
Depreciation of Fixed Assets	$ 51,851	$ 49,288	$ 2,563	**5.2%**

Note 1: Recognized as income tax for financial reporting purposes

The following table provides a comparison of the depreciation of fixed assets for 2015, 2014 and 2013:

($000's)	2015	2014	2013	Variance 2015-2014	Variance 2014-2013
Depreciation of Fixed Assets	$ 51,851	$ 49,288	$ 46,964	$ 2,563	$ 2,324

Depreciation of fixed assets for 2015 is $51,851,000 as compared to $49,288,000 for 2014, representing a 5.2% increase. The change is attributable to an increase of depreciable assets by approximately $73,145,000.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006), P.U. 32 (2007) and P.U. 13 (2013), as well as the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2010 have been incorporated into the Company's depreciation calculations for 2015.

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 2013 to 2015:

(000's)	**Actual 2015**	**Actual 2014**	**Acutal 2013**	**Variance 2015-2014**
Interest				
Long-term debt	**$ 35,020**	$ 36,327	$ 35,123	$ (1,307)
Other	**1,139**	645	1,092	494
Amortization				
Debt costs	**242**	254	302	(12)
Interest charged to construction	**(677)**	(776)	(483)	99
Total Finance charges	**$ 35,724**	$ 36,450	$ 36,034	$ (726)
Year over year percentage change	**-1.99%**	1.15%	0.50%	

In the above table, finance charges decreased by approximately $0.7 million, from $36.4 million in 2014 to $35.7 million in 2015. The lower finance costs reflect interest savings associated with the maturity of $29 million, 10.55% first mortgage sinking fund bonds on August 1, 2014. These savings were partially offset by interest costs associated with the $75 million, 4.446% first mortgage sinking fund bonds issued in September 2015 and higher short-term borrowings in 2015.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2015 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2015 and have noted that the effective income tax rate decreased from 22.2% in 2014 to 21.7% in 2015. 2015 and 2014 results in the following effective rates:

	2015	2014	2015-2014
Income tax expense	$ 10,925	$ 10,795	$ 130
Earnings before income tax	$ 50,239	$ 48,635	$ 1,604
Effective income tax rate	21.7%	22.2%	-0.5%

The effective rate decreased by 0.5% in 2015 compared to 2014. The primary reason for this was that there was an increase in items capitalized for accounting purposes but expensed for income tax purposes in 2015. There was no change in the statutory tax rate for 2014 and 2015 which remained at 29%.

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 2015 is unreasonable.

Costs Associated with Curtailable Rates

In 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 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 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 $345,837 for the current period compare to a total of $241,622 for the same period during the previous year. The credit total for the 2014-2015 winter season is higher than the previous season's total primarily due to higher contracted load curtailment.

Prior to the winter season, the Company contacted large general service customers that could potentially participate in the Curtailable Service Option. Through the process the Company procured an additional participant with load curtailment potential of approximately 2.6 MW. This addition was partially offset by the election of two existing Option participants, representing approximately 0.7 MW in load curtailment, to not participate in the Option during the 2014-2015 winter season.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and 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 2015 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2015 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 2015	Actual 2014	Actual 2013	Variance 2015-2014
Charged from Fortis Companies:				
Annual report and quarterly reports	**$ 73,000**	$ 98,000	$ 90,000	$ (25,000)
Directors' fees and travel	**166,000**	373,000	185,000	(207,000)
Hotel/Banquet Facilities	**-**	7,100	-	(7,100)
Staff charges	**944,000**	849,000	558,000	95,000
Miscellaneous	**489,000**	663,600	634,200	(174,600)
	1,672,000	1,990,700	1,467,200	(318,700)
Performance and restricted share units	**276,800**	147,400	65,000	129,400
Donations and charitable advertising	**273,700**	331,100	221,200	(57,400)
Executive short term incentive	**272,600**	285,200	257,000	(12,600)
Miscellaneous	**39,100**	46,500	32,400	(7,400)
	2,534,200	2,800,900	2,042,800	(266,700)
Less: Income Taxes	**734,900**	812,200	592,400	(77,300)
Less: Part VI.1 tax adjustment	**-**	-	12,814,000	-
Total non-regulated (net of tax)	**$1,799,300**	$ 1,988,700	$ (11,363,600)	$ (189,400)

In the table above the most significant fluctuation between 2015 and 2014 pertains to the Charges from Fortis Companies, which is a decrease of $318,700. The variance is primarily due to these amounts including executive stock option expenses of $147,009 in 2015 and $321,602 in 2014.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2015 this represents an addition to non-regulated expenses (before tax adjustment) of $272,600 (2014 - $285,200). 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 29.0% which agrees with the Company's statutory rate as identified in the 2015 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 2014 and 2015:

(000's)	2015 Actual	2014 Actual	Variance 2015-2014
Regulatory Assets			
Rate stabilization account	**$ 960**	**$ 2,342**	$ (1,382)
OPEBs asset	**35,040**	**38,544**	(3,504)
Pension deferral	**-**	**281**	(281)
Cost recovery deferral	**-**	**1,576**	(1,576)
Cost of capital cost recovery deferral	**-**	**828**	(828)
Revenue shortfall deferral	**-**	**1,586**	(1,586)
Deferred GRA costs	**-**	**322**	(322)
Conservation and demand management deferral	**10,511**	**6,953**	3,558
Optional seasonal rate revenue and cost recovery account	**60**	**97**	(37)
Employee future benefits	**113,044**	**128,237**	(15,193)
Weather normalization account	**6,212**	**46**	6,166
Deferred income taxes	**179,532**	**176,707**	2,825
	$345,359	**$357,519**	$ (12,160)
Regulatory Liabilities			
Weather normalization account	**$ -**	**$ 2,335**	$ (2,335)
Future removal and site restoration provision	**139,700**	**135,357**	4,343
Demand management incentive account	**-**	**628**	(628)
Excess earnings	**68**	**68**	-
	$139,768	**$138,388**	$ 1,380

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. The rates for July 1, 2015 were approved by the Board in P.U. 18 (2015).

As of December 31, 2015, there was a charge to the RSA of $3,078,500 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007) and P.U. 43 (2009), and the Wholesale Rate Change Flow-Through Account approved in P.U. 18 (2015).

Pursuant to 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, 2015, the debit balance of $1,701,520 in the OPEBVDA account was transferred to the RSA.

Pursuant to 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, 2015, the balance of $4,935,256 in the PEVDA account was credited to the RSA.

Pursuant to 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, 2015 $46,339 was credited to the RSA in accordance with P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account, the Optional Seasonal Rate Revenue and Cost Recovery Account, 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 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 P.U. 31(2010).

Pension Deferral

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004). The costs were fully amortized in 2015.

Cost Recovery Deferral

The Cost Recovery Deferral balance relates to the conclusion of the following regulatory amortizations which expired in 2010: 2005 Unbilled Revenue, Municipal Tax Liability, Depreciation, Replacement Energy, Purchased Power Unit Cost Reserve and 2008 GRA Costs. Expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000. On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of the above mentioned deferrals. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 46(2009). In P.U. 30 (2010), the Board approved the deferred recovery, until a further Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which is to be charged with the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differ from the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. In P.U. 22 (2011), the Board approved the deferred recovery, until a further Order of the Board, of an additional $2,363,000 in 2012 due to the conclusion in 2010 of the amortizations. In P.U. 13 (2013) the Board approved amortization of these cost recovery deferrals over three years. Amortization of this account commenced in 2013.The costs were fully amortized in 2015.

Cost of capital cost recovery deferral

The cost of capital cost recovery deferral account reflects the deferred recovery of $2,487,000 reflecting the difference between the 8.38% return on equity currently in customer electricity rates and the 8.80% return on equity approved in P.U. 17 (2012). In P.U. 13 (2013) the Board approved a three year amortization of the cost of capital recovery deferral. Amortization of this account commenced in 2013. The costs were fully amortized in 2015.

Deferred general rate application costs

In P.U. 13 (2013) the Board approved the deferral of cost related to 2013/2014 GRA as well as amortization of this deferral over a three year period commencing in 2013. Actual costs incurred and deferred were approximately $965,000 with amortization of $321,000 incurred in 2013 and $322,000 in 2014. The costs were fully amortized in 2015.

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 P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In 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 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, 2015 were $10,511,000 (before tax) with amortization of $1,053,264 in 2015.

Optional Seasonal Rate Revenue and Cost Recovery Account

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2015 was $69,298. This balance was transferred to the RSA on March 31, 2016 pursuant to the Board's approval in P.U. 10 (2016).

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 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 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 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 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 P.U. 11 (2012), to be amortized over 15 years commencing in 2013.

As of December 31, 2015 the regulated asset for employee future benefits was $113,044,000.

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, 2015 was $179,532,000.

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.

In P.U. 13 (2013) the Board approved the amortization of the December 31, 2011 year-end balance of the weather normalization account of $7,006,000 ($5,020,000 after future income tax) over a three year period beginning in 2013, representing an amortization of approximately $2,335,000 ($1,673,000 after future income tax) each year; 2015 was final year for the amortization. In addition, commencing in 2013, P.U. 13 (2013) also 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 P.U. 11 (2016) the Board approved the December 31, 2015 net regulatory asset balance in the Weather Normalization Account of $6,212,000 ($4,410,537 net of future income tax).

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 2015 the balance in this account was $139,700,000 (2014 - $135,357,000).

Demand Management Incentive Account

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (I) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2014, the variation in the account was a regulatory liability of $627,503. This balance was transferred as a credit to the RSA on March 31, 2015 pursuant to the Board's approval in P.U. 8 (2015). The 2015 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband.

Excess earnings

Excess earnings are the earnings that exceed the upper limit of the allowed range of return on rate base of 7.68% approved by the Board in P.U. 51 (2014) for 2015 and 8.06% approved by the Board in P.U. 23 (2013) for 2014. For 2015 and 2014 the Company's regulated earnings did not exceed the upper limit and therefore there is $Nil excess earnings reported on the 2015 Return 13.

In 2013, the Company's regulated earnings exceeded the upper limit of allowed regulated earnings by $68,000 ($49,000 after tax) (see Return on Rate Base and Equity, Capital Structure and Interest Coverage for details).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2015 are unreasonable.

Pension Expense Variance Deferral Account

Scope: *Review of calculation of the Pension Expense Variance Deferral Account ("PEVDA") and assess compliance with P.U. 43 (2009)*

In 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 2015 PEVDA was calculated at $4,935,256. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2015 in accordance with P.U. 43 (2009).

We confirm that the 2015 PEVDA is calculated in accordance with 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 P.U. 31(2010)***

In 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 2015 OPEBVDA was calculated at $(1,701,520). This balance was transferred to the Rate Stabilization Account as a credit on March 31, 2015 in accordance with P.U. 31 (2010).

We confirm that the 2015 OPEBVDA is calculated in accordance with P.U. 31 (2010).

Optional Seasonal Rate Revenue and Cost Recovery Account

Scope: ***Review of calculation of the Optional Seasonal Rate Revenue and Cost Recovery Account and assess compliance with P.U. 8 (2011) and P.U. 13 (2013)***

In P.U. 8 (2011) and P.U. 10 (2014) the Board approved Rate #1.1S Domestic Seasonal – Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates (the "TOD Rate Study"). On December 31st of each year from 2011 until further order of the Board, this account is to 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 P.U. 13 (2013) the Board approved to maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until the next general rate application.

In accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the first day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. This application for the disposition of the 2015 balance was filed February 26, 2016, within the deadline.

The Optional Seasonal Rate Revenue and Cost Recovery Account balance at December 31, 2015 was \$69,298. This balance was approved to be transferred to the Rate Stabilization Account as a charge as of March 31, 2016 in P.U. 10 (2016).

Nothing has come to our attention to indicate that the Company is not in compliance with P.U. 8 (2011) and P.U. 13 (2013).

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 2015 are as follows:

1. Made capital investments of $101 million of which over 49% 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 Company now has over 66% Automated Meter Reading ("AMR") penetration Island-wide. Newfoundland Power has reduced the number of meter reading estimates in 2015 by over 40% from 2014. AMR technology enables collection of unscheduled meter readings while driving to the scheduled routes. This additional data eliminated approximately 53,000 estimates in 2015.

5. The Company completed updates to its website, launching full self-service options for landlords and property managers. The new features allow landlords to sign-up for a landlord agreement online, manage properties on their existing agreement and track the status of their properties.

6. The Company completed an upgrade to its field work scheduling system. This provided a number of work flow improvements such as allowing crews to create work orders in the field and allowing drawings and pictures to be attached to work orders electronically.

7. Approximately 89,000 or 35% of total billed accounts are now using ebills. Internal promotion via the Contact Centre continues to be a strong driver of growth. A customer contest (Say Yes to Paperless) was conducted again in this quarter. In addition, emails allowing a simple "one-click signup" were forwarded to all customers who had an email address on the Company's system but were not previously receiving ebills.

8. The Company completed an island wide implementation of electronic tailboards and voice recorded job steps for pre-job hazard assessments. Daily hazard assessments for line operations are completed via an electronic tailboard form, including voice recordings detailing the job steps, and are attached to the crews' work orders in the scheduling system. The use of this technology enhances the quality of job safety planning through monitoring, feedback and coaching.

9. The functionality of customer outage alerts was expanded to include planned outage notifications. This allows the Company to make customers aware of planned power interruptions in their neighborhood up to 48 hours in advance of the event. The service also offers updates when the planned interruption changes, and when it actually begins and ends. There are now over 8,000 customers signed up to receive outage alerts via text or email.

10. Centralized dispatch and mobile work management technology were key contributors to field service improvements in 2015. Customer requests for location of underground distribution cables were integrated into the centralized scheduling and dispatching process.

11. In 2015, the Company started a two year project to collect electrical system connectivity information for all customers in preparation for the implementation of a new Outage Management system. Approximately 50% of all customer connectivity data was compiled in the Company's geographic information system ("GIS") in 2015, as planned. Operations staff rely on GIS for electrical system diagrams, customer, work order, outage ticket and vehicle locations, dispatching work and improving communication with customers.

12. Continued the Substation Modernization and Refurbishment program in total 70% of the distribution feeders are now automated.

13. Implemented an Electronic Truck Inspection system to allow drivers to more easily meet legislated inspection requirements.

14. Continued to install down line reclosers to provide for improved control of the distribution 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 of the Company:

Category	Measure	Actual 2013	Actual 2014	Actual 2015	Plan 2015	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.23	2.93	2.36	2.38	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.71	2.44	2.11	1.64	No
	Plant Availability (%)	93.0	94.4	94.9	95.0	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	86.0	83.5	86.0	87.0	No
	Call Centre Service Level (% per second)	80/60	80/60	82/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	85.0	81.0	86.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	1.1	1.2	0.5	1.3	Yes
Financial	Earnings (millions)[2]	$36.6	$37.3	$38.8	$37.1	Yes
	Gross Operating Cost/Customer[3]	$243	$259	$249	$260	Yes

[1]2014 reliability statistics above exclude the impact of the January Newfoundland and Labrador Hydro (NLH) system problems. 2013 reliability statistics reported above exclude the impact of the January NLH system problems and the November blizzard in Central and Western.
[2] Excludes $12.8m recovery related to Part VI.I tax in 2013.
[3] Excludes pension, OPEBs and early retirement costs.

The following table compares whether the company measures were achieved during the 2013, 2014, and 2015 years:

Category	Measure	Measure Achieved 2013	Measure Achieved 2014	Measure Achieved 2015
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	No	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	No	No	No
	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	No	Yes
Safety	All Injury/Illness Frequency Rate	Yes	Yes	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	No	Yes

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2016 Annual Financial Review of Newfoundland Power Inc.

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Board of Commissioners of Public Utilities
2016 Annual Financial Review of Newfoundland Power Inc.

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Restrictions, Qualifications and Independence

Purpose

This report was prepared for the Board of Commissioners of Public Utilities in Newfoundland and Labrador. The purpose of our engagement was to present our observations, findings and recommendations with respect to our 2016 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 2016 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 2016 was $1,061,044,000 compared to average rate base for 2015 of $1,019,082,000. The Company's calculation of the return on average rate base for 2016 was 7.31% (2015 - 7.48%). The actual rate of return was within the range approved by the Board (7.03% to 7.39%). 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 2016 was $475,765,000 (2015 - $451,501,000). The Company's actual return on average common equity for the year ended December 31, 2016 was 8.90% (2015 – 8.98%). 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 2016 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2016 was 8.90% 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 13.36% under budget in 2016. The capital expenditures were under the approved budget (including projects carried over from prior years) on a net basis by $5,557,000 (4.24%). However, for each category of expenditure, the variances ranged from an over-budget of 16.63% to an under-budget of 29.77%. Significant variances are explained in our report.

The Company experienced a 3.40% increase in revenue from rates in 2016 as compared to 2015. The increase can be explained by higher customer energy rates.

Net operating expenses in 2016 decreased by $5,356,000 from 2015, which is primarily due to a decrease in Pension and early retirement expenses. This cost and other 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 2016 are unreasonable.

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 2016 the Company met six out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey", and "All Injury/Illness Frequency Rate."

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2016 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 2016 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 2016/2017 General Rate Application ('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, 2016 have been audited by Ernst and Young LLP, Chartered Professional Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 7, 2017. 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 30, 2017, the Company filed a revised system of accounts as part of its 2016 Annual Report. In submitting these changes the Company noted that the revisions mainly relate to an account approved by the Board resulting from the 2016 General Rate Application and the elimination of accounts that are no longer required.

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, 2016 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 2016 was $1,061,044,000 which is an increase of $41,962,000 (4.12%) over the average rate base for 2015 of $1,019,082,000. 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 2016; 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 2016, 2016 Test Year and 2015 (all figures shown are averages):

(000)'s	2016	Test Year 2016	2015
Net Plant Investment (average)			
Plant Investment	$1,703,478		$1,629,189
Accumulated Depreciation	(681,742)		(657,233)
CIAC's	(35,166)		(33,970)
	986,570	987,068	937,986
Additions to Rate Base (average)			
Deferred Charges (a)	96,877	96,830	101,448
Cost Recovery Deferral for Seasonal/TOD Rates (b)	25	25	59
Cost Recovery Deferral for Hearing Costs (c)	341	400	161
Cost Recovery Deferral for Regulatory Amortizations (d)	-	-	553
Cost Recovery Deferral – 2012 Cost of Capital (e)	-	-	294
Cost Recovery Deferral – 2013 Revenue Shortfall (f)	-	-	563
Cost Recovery Deferral – Conservation (g)	9,384	8,893	6,200
Customer Finance Programs (h)	1,276	1,174	1,174
Weather Normalization (i)	3,066	2,205	1,386
	110,969	109,527	111,838
Deductions from Rate Base (average)			
Other Post-Employment Benefits (j)	42,646	42,519	35,822
Customer Security Deposits (k)	1,036	993	973
Accrued Pension Obligation (l)	5,120	5,111	4,795
Deferred Income Taxes (m)	1,727	1,794	1,899
Excess Earnings (n)	25	25	49
Demand Management Incentive Account (o)	-	-	223
Cost Recovery Deferral – 2016 Cost Recovery Deferral (p)	723	733	-
	51,277	51,175	43,761
Average Rate Base before Allowances	1,046,262	1,045,420	1,006,063
Rate Base Allowances			
Materials and Supplies	6,464	6,485	6,280
Cash Working Capital	8,318	8,429	6,739
	14,782	14,914	13,019
Average Rate Base	$ 1,061,044	$ 1,060,334	$ 1,019,082

(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 $96,877,000 (2015 - $101,448,000) included in the 2016 rate base consists of average deferred pension costs of $96,802,000 (2015 - $101,384,000) and credit facility costs of $75,000 (2015 - $64,000). 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". The calculation of the 2016 average rate base incorporates $25,000 (2015 - $59,000) related to this deferral account.

(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 $171,000 was recorded in 2016, relating to these costs. The 2016 average rate base includes an addition of $341,000 (2015 - $161,000) which represents the unamortized average balance of the original $853,000.

(d) On August 31, 2010 Newfoundland Power submitted an application proposing to defer recovery, until a further Order of the Board, of the amount of $2,363,000 ($1,642,000 after tax) in 2011 to offset the net impact of the expiring amortizations relating to the Municipal Tax Liability, Unrecognized 2005 Unbilled Revenue, Deferred Energy Replacement Costs and the Purchased Power Unit Cost Variance Reserve. This application was approved by the Board in Order No. P.U. 30 (2010). Order No. P.U. 22 (2011) approved the deferral in 2012 of an additional $2,363,000 ($1,678,000 after tax) related to these expiring amortizations. In Order No. P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Amortization of approximately $1,107,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $553,000 (2014 - $1,661,000) which represents the unamortized average balance of the original $3,320,000. These costs were fully amortized as of December 31, 2015.

(e) In Order No. P.U. 17 (2012) the Board approved the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs. In Order No. P.U. 13 (2013) the Board approved three year amortization of these deferrals commencing January 1, 2013. Amortization of approximately $588,000 was recorded in each of the three years; 2013, 2014 and 2015, relating to these costs. The 2015 average rate base includes an addition of $294,000 (2014 - $883,000) which represents the unamortized average balance of the original deferral. These costs were fully amortized as of December 31, 2015.

(f) In Order No. P.U. 13 (2013) the Board approved the deferral and amortization over three years of amounts related to Newfoundland Power's shortfall in the recovery of revenue requirements for 2013. As a result of this order and updated revenue forecasts subsequently filed by Newfoundland Power in an *Application Filed in Compliance with Order No. P.U. (2013)*, an amount of $3,965,000 ($2,815,000 after tax) has been deferred. Based on a rate implementation date of July 1, 2013, the amortization period had subsequently been updated to 30 months, resulting in amortization for 2013 of $563,000 and amortization of $1,126,000 for 2014 and 2015. The 2015 average rate base includes an addition of $563,000 (2014 - $1,689,000) which represents the unamortized average balance of the original 2,815,000. These costs were fully amortized as of December 31, 2015.

(g) In Order No. P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan. These costs were fully amortized in 2013. 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. Included in the calculation of the average rate base for 2016 is $9,384,000 (2015 - $6,200,000) related to this deferral.

(h) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2016 average rate base incorporates $1,276,000 (2015 - $1,174,000) related to these programs.

(i) During 2016, 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 $4,411,000 in 2016 (2015 – $33,000 increase).

Other transfers:

i. $102,000 transfer increase (2015 – $108,000 decrease) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $1,823,000 transfer decrease (2015 - $4,303,000 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 $2,690,000 (2015 - $6,051,000 decrease). The ending balance in this reserve account totaled ($1,721,000) compared to a balance of ($4,411,000) at December 31, 2015 (an average of ($3,066,000) for 2016 (2015 – ($1,386,000)).

(j) Other Post-Employment Benefits is equal to the difference, at December 31, 2016, between the OPEBs liability of $77,619,000 and the OPEBs asset of $31,536,000. The calculation of the 2016 average rate base of $42,646,000 is equal to the average of the December 31, 2016 net liability of $46,083,000 and the December 31, 2015 net liability of $39,208,000.

(k) 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 2016 average rate base incorporates $1,036,000 (2015 - $973,000) related to customer security deposits.

(l) The 2016 average rate base calculation incorporates $5,120,000 (2015 - $4,795,000) 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.

(m) 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 2016 average rate base is ($1,179,000) and ($11,457,000) respectively. The remaining balance of the deferred income tax liability in the amount of $14,363,000 relates to capital assets. This results in an average balance for deferred income tax liability of $1,727,000 (2015 - $1,899,000).

(n) 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 2016 average rate base incorporates $25,000 (2015 - $49,000) related to this account.

(o) In Order No. P.U. 7 (2014) the Board approved the disposition of the 2013 balance of the Demand Incentive Account of $383,085 (($271,990) after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2014. In Order No. P.U. 8 (2015) the Board approved the disposition of the 2014 balance of the Demand Incentive Account of $627,503 ($445,527 after tax) by means of a credit to the Rate Stabilization Account as of March 31, 2015. The 2015 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband. The 2016 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband. The 2016 average rate base incorporates $Nil (2015 - $223,000) related to this account.

(p) 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 ($361,000) was recorded in 2016, relating to this over-recovery of revenue. The 2016 average rate base includes deduction of $723,000 (2015 - $Nil) which represents the unamortized average balance of the original $1,806,000.

The net change in the Company's average rate base from 2015 to 2016 can be summarized as follows:

(000's)	2016	2015
Average rate base - opening balance	$ 1,019,082	$ 964,930
Change in average deferred charges and deferred regulatory costs	(3,375)	(1,615)
Average change in:		
Plant in service	74,289	82,016
Accumulated depreciation	(24,509)	(22,497)
Contributions in aid of construction	(1,197)	(1,164)
Weather normalization reserve	1,681	4,735
Other post employment benefits	(6,824)	(7,847)
Future income taxes	172	302
Rate base allowances	1,763	996
Other rate base components (net)	(38)	(774)
Average rate base - ending balance	$ 1,061,044	$ 1,019,082

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2016 average rate base, and therefore conclude that the 2016 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 2016 was 7.31% (2015 – 7.48%). 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 2016, 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 2014 to 2016 is set out in the table below.

	2016	**2015**	**2014**
Actual Return on Average Rate Base	7.31%	7.48%	7.83%
Upper End of Range set by the Board	7.39%	7.68%	8.06%
Lower End of the Range set by the Board	7.03%	7.32%	7.70%

The Board approved the Company's rate of return on average rate base of 7.21% in a range of 7.03% to 7.39% for 2016 in Order No. P.U. 25 (2016). As noted above, the Company's actual return on average rate base for 2016 was 7.31% which was inside the range set by the Board.

The actual rate of return for 2015 was within the range set by the Board.

The actual rate of return for 2014 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 2016 as reported in Return 24 is as follows:

	2016 Average		2015	2014
	(000's)	**Percent**	Percent	Percent
Debt	**$572,841**	**54.17%**	54.85%	54.85%
Preferred equity	**8,935**	**0.84%**	0.88%	0.92%
Common equity	**475,765**	**44.99%**	44.27%	44.23%
	$1,057,541	**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 2016 test year in Return 26. The embedded cost of debt for 2016 was 6.27% which represents a 23 bps decrease from 2015 embedded cost of debt of 6.50%.

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, 2016 is included on Return 27 of the annual report to the Board. The average common equity for 2015 was $475,765,000 (2015 - $451,501,000). The Company's actual return on average common equity for 2016 was 8.90% (2015 – 8.98%).

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 2015 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 2016 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2016 was 8.90% 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)	**2016**	2015	2014
Net income	**$40,508**	$ 39,314	$ 37,840
Income taxes	**11,851**	10,925	10,795
Interest on long term debt	**34,846**	35,020	36,327
Interest during construction	**(1,304)**	(1,240)	(1,435)
Other interest and amortization of debt discount costs	**1,090**	1,361	880
Total	**$86,991**	$ 85,380	$ 84,407
Interest on long term debt	**$34,846**	$35,020	$36,327
Other interest and amortization of debt discount costs	**1,090**	1,361	880
Total	**$35,936**	$36,381	$37,207
Interest Coverage (times)	**2.4**	2.3	2.3

The above table shows that the interest coverage increased by 0.1 times from 2015 to 2016.

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 2016 is 2.4 times.

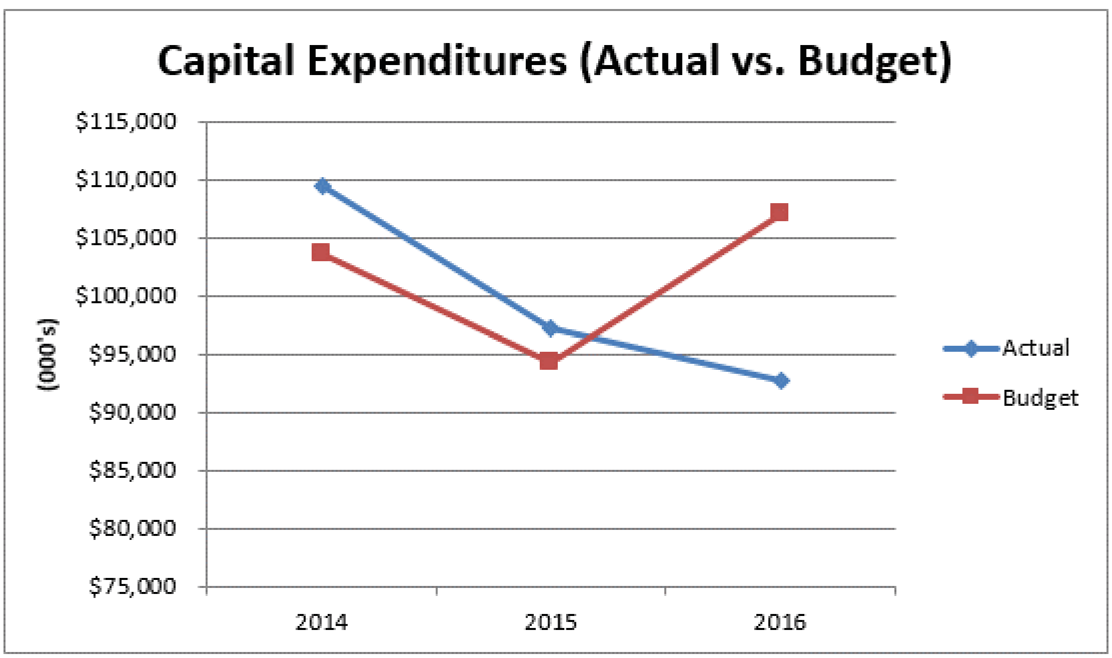
Capital Expenditures

Scope: ***Review the Company's 2016 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 2014 to 2016:

($000's)	2014	2015	2016	Notes
Actual	$ 109,429	$ 97,155	$ 92,727	1
Budget	$ 103,572	$ 94,211	$ 107,028	
Over (under) budget	5.66%	3.12%	(13.36%)	

Note 1: Total expenditures per the 2016 Capital Budget report includes the carryover amount of $7,284,000 for a total of $100,011,000. The carryover amount is made up of seven projects included in the following categories: $637,000 to generation - hydro; $1,064,000 to substations; $898,000 to transmission; $2,574,000 to distribution; $1,024,000 to Transportation; $150,000 to Telecommunications, and $937,000 to information systems. According to the Company, these expenditures will occur in 2017.



The following table provides a summary of the capital expenditure activity in 2016 as reported in the Company's *"2016 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2016 (1)	Total	Prior Years	2016	Total
2016 Capital Projects	$ -	$ 88,450	$ 88,450	$ -	$ 74,564	$ 74,564
2015 Projects Carried to 2016 & Multi Year Projects						
Facility Rehabilitation - 2015	1,586	-	1,586	1,365	14	1,379
Substation Refurbishment and Modernization - 2015 (2)	9,961	-	9,961	10,777	233	11,010
Rebuild Transmission Lines - 2015 (3)	5,731	-	5,731	5,731	759	6,490
Trunk Feeders - 2015 (4)	991	-	991	683	72	755
Pierre's Brook Plan Refurbishment - Multi Year	750	15,012	15,762	639	14,154	14,793
Company Building Renovations - Duffy Place - Multi Year (5)	2,068	724	2,792	1,049	2,562	3,611
SCADA System Replacement - Multi Year	2,833	2,842	5,675	1,620	3,715	5,335
	23,920	18,578	42,498	21,864	21,509	43,373
Grand Total	**$ 23,920**	**$ 107,028**	**$ 130,948**	**$ 21,864**	**96,073 (6)**	**$ 117,937**

(1) Approved by Order No. P.U. 28 (2015).
(2) The Company has noted that the unfavorable budget variance was related to the price of major equipment purchases and installation contract pricing obtained through competitive tendering, being higher then budget estimates.
(3) The Company has noted that the unfavorable variance was associated with the 400L rebuild project in the Stephenville Area. Additional expenses were incurred on the project due to the environmental conditions encountered on the right of way. The construction of corduroy roads to access the site were required because a large section of the work was located in a very wet and boggy area. Additionally, an extra expenditure was incurred to upgrade an access from the Trans-Canada Highway to meet Department of Transportation specifications.
(4) The Company has noted that the budget variance primarily resulted from delays in proceeding with planned underground vault upgrades due to easement acquisition difficulties and the need to coordinate the required outages with the downtown St. John's business community. The work is now planned to be addressed in 2017.
(5) The Company has noted that the budget variance is primarily related to more work being required to upgrade the HVAC system than anticipated, and pricing obtained through a competitive tender also being higher than expected.
(6) Represents $92,727,000 and $3,346,000 in actual expenditures relating to 2016 and 2015 capital projects, respectively.

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

($000's)	2016 Budget (1)	2016 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	$ 19,693	$ 17,983	$ (1,710)	$ 807	$ (903)	(4.59%)
Generation - Thermal	1,738	1,515	(223)	-	(223)	(12.83%)
Substation	27,901	24,498	(3,403)	1,064	(2,339)	(8.38%)
Transmission	11,798	10,536	(1,262)	898	(364)	(3.09%)
Distribution	46,046	42,577	(3,469)	2,574	(895)	(1.94%)
General property	3,908	4,558	650		650	16.63%
Transportation	3,258	2,353	(905)	1,024	119	3.65%
Telecommunications	514	211	(303)	150	(153)	(29.77%)
Information systems	10,842	9,743	(1,099)	937	(162)	(1.49%)
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	4,500	3,963	(537)	-	(537)	(11.93%)
Total	**$ 130,948**	**$ 117,937**	**$ (13,011)**	**$ 7,454**	**$ (5,557)**	**(4.24%)**

1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.

2 - 2016 actuals include the total expense for projects carried forward from 2015.

3 - Represents $7,284,000 included in the 2016 budget and an amount of $170,000 from a 2015 project, but not yet spent.

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 $13,011,000 and by $5,557,000 (4.24%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 16.63% for the General property category to an under-budget of 29.77% 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		437
Public Safety Around Dams		200
Substation Refurbishment and Modernization		1,064
Transmission Line Rebuild		898
Trunk Feeders		177
Distribution Reliability Initiative		750
Distribution Feeder Automation		203
St. John's Main Underground Refurbishment		1,444
Purchase of Vehicles and Aerial Devices		1,024
Fibre Optic Network		150
Application Enhancements		154
System Upgrades		420
Outage Management System Replacement		87
SCADA System Replacement		276
Facility Rehabilitation - 2015		170
Total Carryover	**$**	**7,454**

The Company has provided detailed explanations on budget to actual variances in its "2016 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 2016 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 3.12% in 2015 and -13.36% in 2016 resulting in no additional reporting requirements.

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.

<u>Capital Expenditure Reports</u>

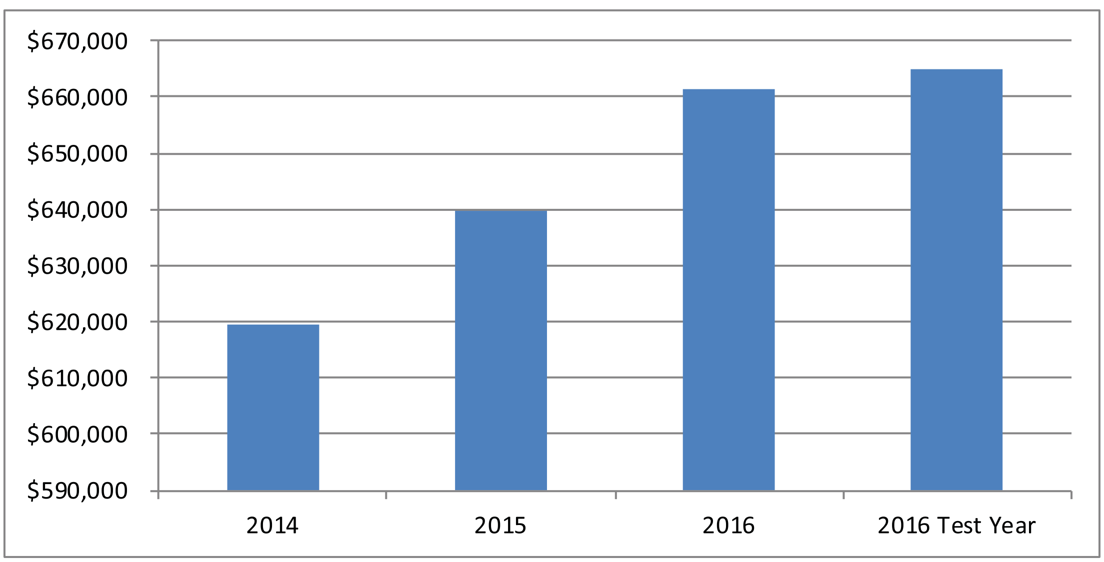
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2016 calendar year.

Revenue

Scope: Review the Company's 2016 revenue in comparison to prior years and follow up on any significant variances.

We have compared the actual revenues for 2014 to 2016 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2014	2015	2016	2016 Test Year
Residential	$ 390,614	$ 403,910	$ 420,159	$ 422,171
General Service				
0-100 kW	82,080	85,093	88,362	88,976
110-1000 kVA	88,789	93,725	96,404	97,267
Over 1000 kVA	39,743	38,400	38,021	37,889
Streetlighting	15,262	15,541	15,928	15,918
Discounts forfeited	3,016	2,962	2,507	2,894
Revenue from rates	$ 619,504	$ 639,631	$ 661,381	$ 665,115
Year over year percentage change	5.57%	3.25%	3.40%	



The above graph demonstrates that the Company has seen a 3.40% increase in revenue from rates in 2016 as compared to 2015. The increase primarily relates to an increase in customer energy rates effective July 1, 2015 and July 1, 2016 related to Order No. P.U. 17 (2015) and Order No. P.U. 18 (2016) respectively. For residential sales there was an increase of 4.02% in 2016 revenue from 2015. GWh sold in this category increased by 0.04%, and the number of residential customers increased by 1.04%.

The comparison by rate class of 2016 actual revenues to 2016 test year is as follows:

($000's)	2015	2016	2016 Test Year	Actual - TY Variance	%
Residential	$ 403,910	$ 420,159	$ 422,171	$ (2,012)	(0.48%)
General Service					
0-100 kW	85,093	88,362	88,974	(612)	(0.69%)
110-1000 kVA	93,725	96,404	97,266	(862)	(0.89%)
Over 1000 kVA	38,400	38,021	37,887	134	0.35%
Streetlighting	15,541	15,928	15,919	9	0.06%
Discounts forfeited	2,962	2,507	2,894	(387)	(13.37%)
Total revenue from rates	$ 639,631	$ 661,381	$ 665,111	$ (3,730)	(0.56%)

We have also compared the 2016 budget energy sales in GWh to the actual sold in 2016:

	2015	2016	2016 Test Year	Actual – TY Variance	%
Residential	3,654.2	3,655.6	3,676.6	(21.0)	(0.57%)
General Service					
0-100 kW	792.4	797.7	805.0	(7.3)	(0.91%)
110-1000 kVA	998.3	1,010.4	1,019.3	(8.9)	(0.87%)
Over 1000 kVA	479.5	453.8	457.1	(3.3)	(0.72%)
Streetlighting	32.2	32.6	32.5	0.1	0.31%
Total	5,956.6	5,950.1	5,990.5	(40.4)	(0.67%)

Actual 2016 revenue from rates was lower than 2016 test year with an overall decrease in actual sales of $3,730,000 (0.56%) from the 2016 test year. There was a 0.67% decrease in GWh sold in 2016 compared to 2016 test year. The largest variances in revenue can be seen in the Residential and 110-1000 KVA class where revenues decreased by $2,012,000 (0.48%) and $862,000 (0.89%) 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.

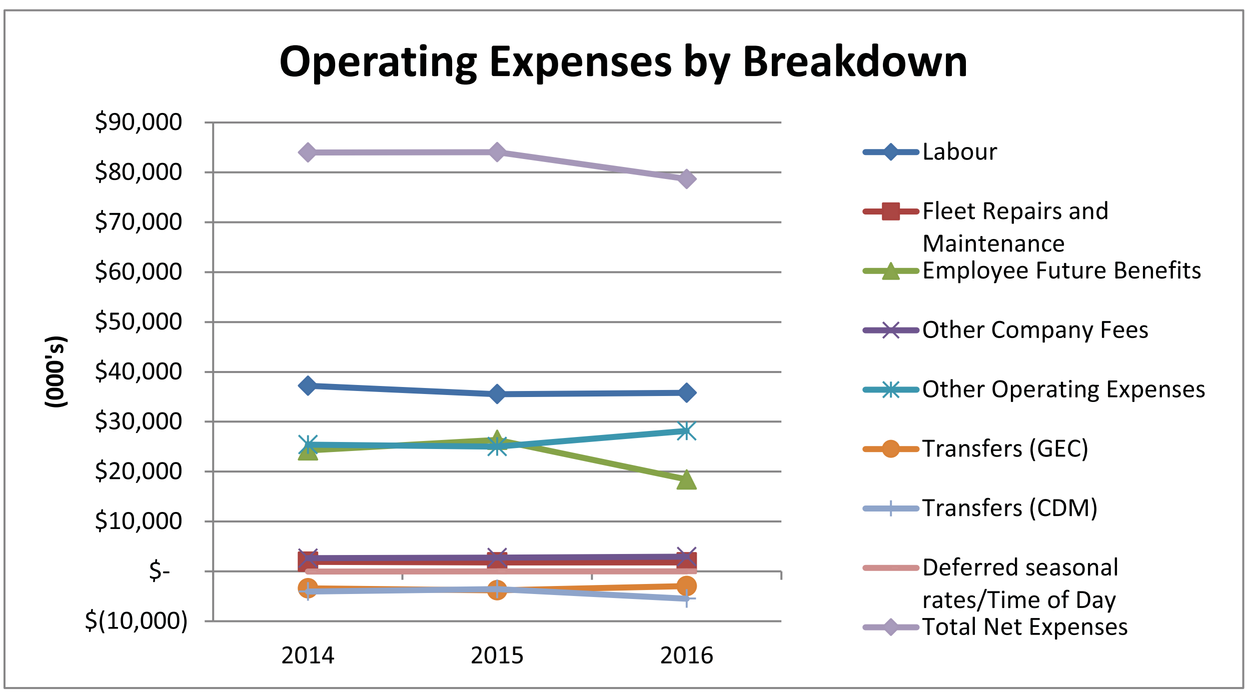
(000's)	Actual 2016	Test Year 2016	Actual 2015	Actual 2014	Variance Actual-Test	Variance 2016-2015
Labour	$ 36,770		$ 36,485	$ 37,871		$ 285
Reclass OPEB labour cost	(981)		(969)	(658)		(12)
Total Labour	35,789	36,898	35,516	37,213	(1,109)	273
Vehicle expense	1,797	1,698	1,786	1,901	99	11
Operating materials	1,425	1,641	1,583	1,857	(216)	(158)
Inter-company charges	2,145	2,197	1,560	1,710	(52)	585
Plants, Subs, System Oper & Bldgs	2,770	2,269	2,367	2,312	501	403
Travel	1,160	1,237	1,052	1,318	(77)	108
Tools and clothing allowance	1,161	1,133	1,130	1,192	28	31
Miscellaneous	1,821	1,954	1,765	1,970	(133)	56
Conservation	4,253	2,280	2,466	1,762	1,973	1,787
Taxes and assessments	1,214	1,150	1,123	1,040	64	91
Uncollectible bills	1,194	1,310	1,313	1,490	(116)	(119)
Insurance	1,293	1,241	1,260	1,243	52	33
Severance & other employee costs	47	73	72	58	(26)	(25)
Education, training, employee fees	275	356	298	310	(81)	(23)
Trustee and directors' fees	471	467	462	431	4	9
Other company fees	2,944	3,354	2,757	2,650	(410)	187
Stationary & copying	266	279	230	266	(13)	36
Equipment rental/maintenance	838	803	746	769	35	92
Communications	2,959	3,139	3,184	3,220	(180)	(225)
Advertising	1,519	1,687	1,251	1,444	(168)	268
Vegetation management	1,820	1,827	1,766	1,789	(7)	54
Computing equipment & software	1,359	1,336	1,058	915	23	301
Total Other	32,731	31,431	29,229	29,647	1,300	3,502
Pension & early retirement program	9,763	9,864	17,702	13,276	(101)	(7,939)
OPEB's	8,678	8,702	8,653	10,968	(24)	25
Total employee future benefits	18,441	18,566	26,355	24,244	(125)	(7,914)
Total gross expenses	86,961	86,895	91,100	91,104	66	(4,139)
Transfers (GEC)	(2,955)	(3,135)	(3,809)	(3,399)	180	854
CDM amortization	1,712	1,713	1,053	420	(1)	659
Deferred CDM program costs	(7,200)	(5,742)	(4,611)	(4,436)	(1,458)	(2,589)
Deferred seasonal rates/TOD	-	-	(9)	(39)	-	9
Deferred regulatory costs	172	200	322	322	(28)	(150)
Total net expenses	$ 78,690	$ 79,931	$ 84,046	$ 83,972	$ (1,241)	$ (5,356)

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2014, 2015, 2016 Test Year and 2016 Actual.

Overall, net operating expenses decreased by 5,356,000 from 2015 to 2016. 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 2016 are unreasonable. The most significant variances between 2016 Test Year and actual are labour and conservation costs. According to the Company, the labour decrease in actual compared to test year is primarily due to a reduction in FTEs reflecting timing of retirements and leaves, timing of implementation of the customer energy conservation program following the approval of the 2016/2017 GRA and advance in meter reading technology. The conservation cost increase in actual compared to test year is due to increased customer uptake on instant rebates for items offering energy savings such as LED light bulbs; the increase in conservation cost is offset by costs deferred to the CDM program deferral account.

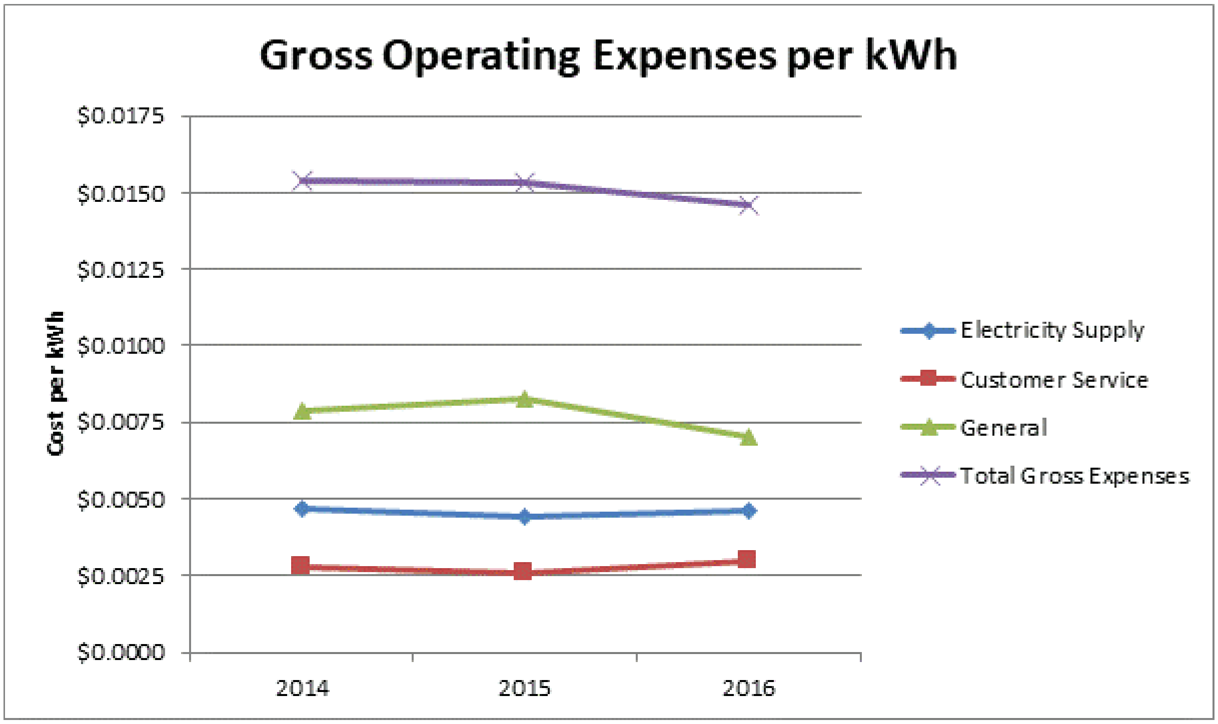
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2014 to 2016.

	Actual		
(000's)	**2014**	**2015**	**2016**
Labour	$ 37,213	$ 35,516	$ 35,789
Fleet Repairs and Maintenance	1,901	1,786	1,797
Employee Future Benefits	24,244	26,355	18,441
Other Company Fees	2,650	2,757	2,944
Other Operating Expenses	25,418	25,008	28,162
Transfers (GEC)	(3,399)	(3,809)	(2,955)
Transfers (CDM)+CDM Amortization	(4,016)	(3,558)	(5,488)
Deferred seasonal rates/Time of Day	(39)	(9)	-
Total Net Expenses	$ 83,972	$ 84,046	$ 78,690



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2014 to 2016 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
2014	5,898,500	$ 27,817	$ 0.0047	$ 16,478	$ 0.0028	$ 46,809	$ 0.0079	$ 91,104	$ 0.0154
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



The table and graph show that total gross expenses per kWh have decreased by approximately 4.6% compared to 2015.

There was a decrease in General Costs of $7.8 million which were partially offset by an increase in Electricity Supply Costs and Customer Service Costs of $1.2 million and $2.2 million respectively. 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 2014 to 2016 (including 2016 plan) is as follows:

	Actual 2016	Plan 2016	Actual 2015	Actual 2014	Actual - Plan	Actual 2016-2015
Executive Group	**6.0**	**6.0**	6.0	5.8	0.0	-
Corporate Office	**20.7**	**21.6**	20.7	22.3	(0.9)	-
Finance	**89.5**	**95.0**	93.5	90.9	(5.5)	(4.0)
Egineering and Operations	**406.9**	**425.0**	418.5	424.4	(18.1)	(11.6)
Customer Relations	**62.8**	**72.7**	68.0	72.9	(9.9)	(5.2)
	585.9	**620.3**	606.7	616.3	(34.4)	(20.8)
Temporary employees	**48.6**	**36.8**	46.3	48.5	11.8	2.3
Total	**634.5**	**657.1**	653.0	664.8	(22.6)	(18.5)

The overall number of FTE's in 2016 compared to 2015 decreased by 18.5. The budgeted number of FTE's in the 2016 Plan was 657.1 versus actual of 634.5. According to the Company, the variances between 2016, 2016 Plan and 2015 are the result of the following:

- Finance is lower than plan and 2015 due primarily to timing of replacement of personnel.
- Engineering and operations is lower than plan and 2015 primarily due to the timing of replacement of personnel for retirements and leaves, as well as labour efficiencies.
- Customer Relations is lower than plan and 2015 primarily due to a shift in Customer Service Representatives from regular to temporary employees and a reduction in Meter Readers resulting from advances in meter reading technology. The decrease is partially offset by the shift of personnel from Corporate Office.
- Temporary Employees is higher than plan and 2015 because of a shift in Customer Service Representatives from regular to temporary employees.

An analysis of salaries and wages by type of labour and by function from 2014 to 2016 is as follows:

(000's)	**Actual 2016**	Actual 2015	Actual 2014	**Variance 2016-2015**
Type				
Internal labour	**$ 63,608**	$ 63,330	$ 62,275	$ 278
Overtime	**4,925**	5,117	6,968	(192)
	68,533	68,447	69,243	86
Contractors	**10,593**	15,232	18,286	(4,639)
	$ 79,126	$ 83,679	$ 87,529	$ (4,553)
Function				
Operating	**$ 36,770**	$ 36,485	$ 37,871	285
Capital and miscellane	**42,356**	47,194	49,658	(4,838)
Total	**$ 79,126**	$ 83,679	$ 87,529	$ (4,553)
Year over year percen	-5.44%	-4.40%	11.32%	

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 2016 were $4,553,000 (-5.44%) lower than 2015.

Internal labour costs in 2016 were higher than 2015 primarily due to normal labour inflation offset by a reduction in full time equivalents reflecting timing of replacement of personnel and labour efficiencies including advances in meter reading technology.

Overtime in 2016 was lower than 2015 because 2015 included increased labour for substation work.

Contract labour for 2016 was lower than 2015 because 2015 included increased contract labour for distribution work such as extensions as well as 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 2014 to 2016 are included in the table below:

	Salary Cost Per FTE				
	Actual 2016	Actual 2015	Actual 2014		Variance 2016-2015
Total reported internal labour costs	**$ 63,608**	$ 63,330	$ 62,275		$ 278
Benefit costs (net)	**(8,470)**	(7,559)	(7,448)		(911)
Other adjustments	**(772)**	(605)	(646)		(167)
Base salary costs	**54,366**	55,166	54,181		(800)
Less: executive compensation	**(1,864)**	(1,750)	(1,932)		(114)
Base salary costs (excluding executive)	**$ 52,502**	$ 53,416	$ 52,249		$ (914)
FTE's (including executive members)	**634.5**	653.0	664.8		
FTE's (excluding executive members)	**630.5**	649.0	661.0		
Average salary per FTE	**85,683**	84,481	81,500		
% increase	**1.42%**	3.66%	3.36%		
Average salary per FTE (excluding executive members)	**83,270**	82,305	79,045		
% increase	**1.17%**	4.12%	3.42%		

The above analysis indicates that the increase in average salary per FTE has decreased in 2016 as compared to 2015 and 2014.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2014 to 2016 and the targets set for 2016:

Measure	Target 2016	Actual 2016	Actual 2015	Actual 2014
Controllable Operating Costs/Customer	**$226.10**	$219.70	$219.80	$223.90
Earnings	**38.3m**	40.0m	38.8m	37.3m
Reliability - Duration of Outages (SAIDI)	**2.36**	2.24	2.36	2.44
Customer Satisfaction - % Satisfied	**86.1%**	86.1%	86.1%	83.5%
Injury Frequency Rate	**0.4**	0.4	0.18	0.51
Regulatory Performance	**Subjective**	140%	140%	150%

2016 STI results were adjusted to remove the impact of severe weather conditions in December. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or 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 2016 is established as a percentage of base pay for the three employee groups. For 2016, all measures relating to 'controllable operating costs/customer', 'earnings', 'SAIDI', 'customer satisfaction', 'safety', and 'regulatory performance' metrics were met.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2014 to 2016:

	Target 2016	**Actual 2016**	**Target 2015**	**Actual 2015**	**Target 2014**	**Actual 2014**
President	50%	67.20%	50%	64.90%	40-50%	64%
Executive	40%	53.90%	40%	51.90%	35%	44.8%
Directors	15%	19.60%	15%	19.60%	15%	19.2%

STI actual payout rates for 'President', 'Executive' and 'Director' employee groups are higher than or equal to the prior year and each payout rate exceeded target consistent with 2015 and 2014.

In dollar terms, the STI payouts for 2014 to 2016 are as follows:

	Actual 2016	**Actual 2015**	**Actual 2014**	**Variance 2016-2015**
President	**$ 242,000**	$ 227,000	$ 360,000	$ 15,000
Executive	**442,000**	401,000	312,000	41,000
Directors	**323,300**	342,200	320,300	- 18,900
Total	**$ 1,007,300**	$ 970,200	$ 992,300	$ 37,100
Year over Year % change	3.82%	-2.23%	-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 2016, the non-regulated portion (before tax adjustment) was $367,818 (2015 - $224,170).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2014 to 2016.

	Base Salary	Short Term Incentive	Other	Total
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**
2014				
Total executive group	$ 1,268,257	$ 672,000	$ 131,845	$ 2,072,102
Average per executive (4)	**$ 317,064**	**$ 168,000**	**$ 32,961**	**$ 518,026**
% Average increase 2016 vs 2015	5.18%	8.92%	113.34%	12.64%

In addition to general salary increases, base salary for the executive group in 2016 increased from 2015 due to the Vice President of Finance/Chief Financial Officer (CFO) being appointed Chief Operating Officer effective July 1, 2016, in addition to responsibilities as CFO. Other compensation for the executive group in 2016 increased from 2015, primarily due to a performance share unit payout received by each of the executive that was not received in prior years. Base salaries, performance share unit payouts and STI payouts were agreed to the Board of Directors' minutes.

Company Pension Plan

For 2016, we reviewed the accounts supporting the gross charge of $9,763,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2014 to 2016, and 2016 test year:

	Actual 2016	Test Year 2016	Actual 2015	Actual 2014	Variance 2016-2015
Pension expense per actuary	**$ 7,330,000**	**$ 7,305,000**	$ 15,332,000	$ 11,084,000	$ (8,002,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**557,000**	**547,000**	562,000	568,000	(5,000)
Group RRSP @ 1.5%	**350,000**	**365,000**	384,000	422,000	(34,000)
Individual RRSP's	**1,531,000**	**1,657,000**	1,421,000	1,211,000	110,000
Less: Refunds (net of other expenses)	**(5,000)**	**(10,000)**	3,000	(9,000)	(8,000)
Total	**$ 9,763,000**	**$ 9,864,000**	$ 17,702,000	$ 13,276,000	$ (7,939,000)
Year over year percentage change	**(44.85%)**		33.34%	(9.96%)	

Overall, pension expense for 2016 is lower than 2015 primarily due to a higher discount rate at December 31, 2015, which is used to determine the pension obligation for 2016, as well as a higher expected service life of active members.

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 0.89% in 2016.

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 7.74% 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 $76,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2015 primarily reflects wage increases and new hires in the year, which was partially offset by retirements and terminations (28 retirements in 2016). The net increase for RRSP expenditures in 2016 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 2014 to 2016 and 2016 test year are as follows:

(000's)	**Actual 2016**	**Test Year 2016**	**Actual 2015**	**Actual 2014**	**Variance 2016-2015**
Accrued OPEBs	**$ 6,089**	**$ 4,661**	$ 6,055	$ 8,038	$ 34
Amortization of transitional balance	**3,504**	**4,932**	3,504	3,504	-
Amount capitalized	**(915)**	**(891)**	(906)	(574)	(9)
Total	**$ 8,678**	**$ 8,702**	$ 8,653	$ 10,968	$ 25

The 2016 OPEBs expense is relatively consistent with the 2015 OPEBs expense.

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 2014 to 2016 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2016 and investigated any unusual items;
- vouched a sample of transactions for 2016 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 2014 to 2016 for charges to and from Newfoundland Power Inc.:

	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charges from related companies				
Regulated	**$ 153,602**	$ 208,781	$ 311,536	$ (55,179)
Non-Regulated	**2,293,715**	1,672,009	1,990,723	621,706
Total	**$ 2,447,317**	$ 1,880,790	$ 2,302,259	$ 566,527
Charges to related companies	**$ 329,339**	$ 229,125	$ 336,758	$ 100,214

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 2016.

- Fortis Inc. estimated its net pool of operating expenses for 2016 as part of its annual business planning process 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. Fortic Inc. used the actual weighted asset basis assets in this calculation.

During the fourth quarter of 2016, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $2,145,000 and are summarized as follows:

2016 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$1,293,000	Non-regulated
Director Fees	184,000	Non-regulated
Consulting and Legal fees	142,000	Non-regulated
Trustee Agent Fees	33,000	Regulated
Audit and Other Fees	43,000	Non-regulated
Public Reporting Costs	43,000	Non-regulated
Annual Meeting Expenses	76,000	Non-regulated
Travel (Board and Other)	47,000	Non-regulated
Insurance (D&O)	45,000	Non-regulated
Other Costs	239,000	Non-regulated
	2,145,000	
Less amounts previously billed:		
Q1 2016	512,000	
Q2 2016	542,000	
Q3 2016	542,000	
Q4 2016 balance owing	$ 549,000	

For 2016, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 4.95%, down from 5.65% in 2014.

As detailed above, trustee agent fees for $33,000 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 2014 to 2016 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 33,000**	$ 35,000	$ 48,000	$ (2,000)
Miscellaneous	**53,059**	24,472	128,593	28,587
Staff Charges	**-**	19,756	-	(19,756)
	$ 86,059	$ 79,228	$ 176,593	$ 6,831
Year over year percentage change	**8.62%**	(55.14%)	162.85%	
Charges to Fortis Inc.				
Printing and stationery	**$ -**	$ 2,191	$ 76	$ (2,191)
Postage and couriers	**7,583**	19,468	25,704	(11,885)
Staff charges	**38,282**	44,430	43,667	(6,148)
Staff charges - insurance	**550**	4,639	38,527	(4,089)
Pole removal and installation	**138**	-	769	138
Miscellaneous	**16,895**	7,855	64,713	9,040
	$ 63,448	$ 78,583	$ 173,456	$ (15,135)
Year over year percentage change	**(19.26%)**	(54.70%)	(44.54%)	

The most significant fluctuations from our analysis of regulated charges from Fortis Inc. is an increase in the miscellaneous account of $28,587 and a decrease in the staff charges account of $19,756. This is primarily due to the transfer of pension plan payments for a Fortis employee who transferred to Newfoundland Power, but remained in the Fortis pension plan. These payments were recorded as "miscellaneous" in 2016 and as "staff charges" in 2015.

The most significant fluctuation from our analysis of regulated charges to Fortis Inc. is an $11,885 decreases in postage and couriers. This is primarily a result of a decrease in the amount of mail processed for Fortis Inc.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2014 to 2016:

(Non-Regulated)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charges from Fortis Inc.				
Director's fees and travel	**231,000**	166,000	373,000	$ 65,000
Annual and quarterly reports	**43,000**	73,000	98,000	$ (30,000)
Staff charges	**1,293,000**	944,000	849,000	$ 349,000
Miscellaneous	**726,715**	489,009	663,602	$ 237,706
	$ 2,293,715	$ 1,672,009	$ 1,983,602	$ 621,706
Year over year percentage change	**37.18%**	(15.71%)	35.20%	

Staff charges increased by $349,000 primarily due to an increase in staff in the investor relations, human resources, planning and forecasting, and information technology functions during the second half of 2015, reflecting a full year impact in 2016. In addition, there was higher share-based compensation due to share price appreciation in 2016.

Miscellaneous charges increased by $237,706, primarily due to an increase in consultant and legal fees from 2015 to 2016 and a Performance Share Unit payout for a former CEO, who retired mid-year 2014 and joined the Fortis Inc. executive team, in the amount of $44,578.

The following table provides a summary and comparison of the other intercompany transactions for 2014 to 2016:

Intercompany Transactions (Other)	**Actual 2016**	**Actual 2015**	**Actual 2014**	**Variance 2016-2015**
Charges to Fortis Properties				
Staff charges	**$ -**	$ 23,569	$ 12,108	$ (23,569)
Staff charges - insurance	**2,950**	21,796	23,753	(18,846)
Stationary costs	**-**	-	288	-
Miscellaneous	**-**	500	790	(500)
	$ 2,950	$ 45,865	$ 36,939	$ (42,915)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ -**	$ 3,113	$ 34,048	$ (3,113)
Miscellaneous	-	48,885	1,664	(48,885)
	$ -	$ 51,998	$ 35,712	$ (51,998)
Charges to Fortis Ontario Inc.				
Staff charges	**$ 22,698**	$ 3,620	$ 3,116	$ 19,078
Staff charges - insurance	**$ 1,794**	$ 5,666	$ 4,986	$ (3,872)
IS charges	**-**	4,065	4,208	(4,065)
Miscellaneous	**400**	390	380	10.00
	$ 24,892	$ 13,741	$ 12,690	$ 11,151
Charges to Maritime Electric				
Staff charges	**$ 34,749**	$ 6,541	$ 3,813	$ 28,208
Staff charges - insurance	**756**	934	1,444	(178)
IS charges	**-**	3,048	2,945	(3,048)
Miscellaneous	**530**	530	510	-
	$ 36,035	$ 11,053	$ 8,712	$ 24,982
Charges from Maritime Electric				
Staff charges	**$ -**	$ -	$ 34,372	$ -
Miscellaneous	**2,880**	250	-	2,630
	$ 2,880	$ 250	$ 34,372	$ 2,630
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 3,538**	$ 182	$ 13,973	$ 3,356

Intercompany Transactions (Other) Cont'd.	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 121,021**	$ 20,779	$ -	$ 100,242
Staff charges - insurance	**-**	-	648	-
Miscellaneous	**1,793**	-	-	1,793
	$ 122,814	$ 20,779	$ 648	$ 102,035
Charges to FortisAlberta Inc.				
Staff charges - insurance	**$ -**	$ 39	$ 76	$ (39)
Miscellaneous	**4,510**	4,260	13,280	250
	$ 4,510	$ 4,299	$ 13,356	$ 211
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 44,744**	$ 49,452	$ 37,611	$ (4,708)
Charges to FortisBC Inc.				
IS charges	**-**	10,363	11,781	$ (10,363)
Staff charges - insurance	**-**	39	-	(39)
Miscellaneous	**2,410**	2,410	2,342	-
	$ 2,410	$ 12,812	$ 14,123	$ (10,402)
Charges from FortisBC Inc.				
Miscellaneous	**$ 7,359**	$ 3,822	$ 3,322	$ 3,537
Charges to Fortis BC Holdings				
Staff charges - insurance	**$ -**	$ -	$ 648	$ -
Miscellaneous	**6,830**	6,780	6,360	50
	$ 6,830	$ 6,780	$ 7,008	$ 50
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 30,111**	$ 22,219	$ 27,113	$ 7,892
Staff charges - insurance	**-**	-	120	-
	$ 30,111	$ 22,219	$ 27,233	$ 7,892
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ 9,022**	$ 23,849	$ 17,074	$ (14,827)
Charges to Fortis Turks and Caicos				
Staff charges	**$ 32,289**	$ 12,271	$ 42,391	$ 20,018
Staff charges - insurance	**-**	-	162	-
Miscellaneous	**3,050**	723	40	2,327
	$ 35,339	$ 12,994	$ 42,593	$ 22,345

The most significant fluctuations from our analysis of other intercompany charges for 2016 compared to 2015 are as follows:

- Staff charges to Fortis Properties decreased by $23,569, due to Fortis Properties being sold by Fortis Inc. in 2015 resulting in no further staff charges.
- Staff charges (insurance) to Fortis Properties decreased by $18,846, which reflects the decrease in insurance claim administration related to Fortis Properties' damage claims as Fortis Properties was sold in 2015.
- Miscellaneous charges from Fortis Properties decreased by $48,885, which reflects charges associated with a Fortis Properties employee's secondment to Newfoundland Power's corporate communication department in 2015.
- Staff charges (insurance) to Fortis Ontario increased by $19,078, due to the sale of Fortis Properties in 2015. After the sale a Newfoundland Power employee continued to adjudicate outstanding Fortis Property insurance claims which had been filed prior to the sale.
- Staff charges to Maritime Electric increase by $28,208, which reflects the labour and travel time charged during the transition period when a staff member assumed the position of Vice President, Customer Service with Maritime Electric in April 2016.
- Staff charges to Belize Electric Company increase by $100,242, which is related to six Newfoundland Power personnel who supplied service to Belize Electric Company in 2016. These services included an audit and engineering and technological consultation.
- Staff Charges to Fortis Turks and Caicos increased by $20,018, which is related to two Newfoundland Power personnel who supplied services to Fortis Turks and Caicos during 2016. These services included safety/work method training and management seminars with Fortis Turks and Caicos management team in preparation for renegotiating their regulatory license.

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 2016 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Other company fees				
Other company fees	$ 2,092	$ 1,601	$ 1,791	$ 491
Regulatory hearing costs	852	1,156	859	(304)
	$ 2,944	$ 2,757	$ 2,650	$ 187
Year over year percentage change	6.8%	4.0%	30.9%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 172	$ 322	$ 322	$ (150)
Year over year percentage change	-46.6%	0.0%	0.0%	

Total company fee costs for 2016 were higher than 2015 actual by $187,000. These costs were higher than 2015 due primarily to increased consultant costs for customer energy conservation programming in 2016, partially offset by lower 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 2014 to 2016 is as follows:

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Miscellaneous	**$ 1,082**	$ 967	$ 1,164	$ 115
Cafeteria and lunchroom Supplies	**89**	84	92	5
Promotional items	**193**	152	120	41
Computer Software	**1**	2	5	(1)
Damage claims	**196**	301	259	(105)
Community relations activities	**3**	3	1	-
Donations and charitable advertising	**202**	188	263	14
Books, magazines and subscriptions	**21**	35	33	(14)
Misc. lease payments	**34**	33	33	1
Total miscellaneous expenses	**$ 1,821**	$ 1,765	$ 1,970	$ 56
Year over year percentage change	**3.17%**	-10.41%	12.51%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2015 to 2016 these expenses have increased by 3.17% overall.

Our procedures in this expense category for 2016 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 2016 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2015 Conservation and Demand Management Report with the Board. This report provided a summary of 2016 CDM activities and costs as well as the outlook for 2016.

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 CPS through in-depth local market research and program cost benefit analysis.

In 2016, 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) introduction of a residential benchmarking program; and (iii) development of an educational initiative to promote mini split heat pumps.

Total CDM costs in 2016 totaled $8,039,000 compared to $5,736,000 in 2015, a $2,303,000 increase. This increase is primarily due to increased customer uptake on instant rebates for items offering energy savings such as LED light bulbs.

In 2016, $7,200,000 ($5,040,000 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 2016 and 2015.

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Vehicle expense	1,797	1,786	1,901	11
Operating materials	1,425	1,583	1,857	(158)
Inter-company charges	2,145	1,560	1,710	585
Plants, Subs, System Oper & Bldgs	2,770	2,367	2,312	403
Travel	1,160	1,052	1,318	108
Tools and clothing allowance	1,161	1,130	1,192	31
Conservation	4,253	2,466	1,762	1,787
Taxes and assessments	1,214	1,123	1,040	91
Uncollectible bills	1,194	1,313	1,490	(119)
Insurance	1,293	1,260	1,243	33
Severance & other employee costs	47	72	58	(25)
Education, training, employee fees	275	298	310	(23)
Trustee and directors' fees	471	462	431	9
Stationary & copying	266	230	266	36
Equipment rental/maintenance	838	746	769	92
Communications	2,959	3,184	3,220	(225)
Advertising	1,519	1,251	1,444	268
Vegetation management	1,820	1,766	1,789	54
Computing equipment & software	1,359	1,058	915	301
Transfers (GEC)	(2,955)	(3,809)	(3,399)	854
CDM amortization	1,712	1,053	420	659

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

- Operating materials costs were lower than 2015 due primarily to the elimination of contracted services for streetlight repairs. This work transitioned to Newfoundland Power staff during 2016.
- Inter-company charges in 2016 were higher than 2015 due to an increase in recoveries charged by Fortis. These charges are non-regulated in nature.
- Plant, subs, system operations and buildings costs in 2016 were higher than 2015 due primarily to higher taxes for hydroelectric generation as a result of the 2016 provincial budget.
- Conservation costs in 2016 were higher than 2015 due to increased customer uptake on instant rebates for items offering energy savings such as LED lightbulbs
- Communication costs in 2016 were lower than 2015 primarily due to lower third party telecommunication service provider costs reflecting favorable contract pricing, implementation of voice over internet protocol in late 2015 and there was an increase in the number of customers participating in electronic billing lowering postage costs.
- Advertising costs were higher than 2015 due to marketing associated with implementing the customer energy conservation program

- Computing equipment & software costs in 2016 were higher than 2015 due to increase in third party software licensing costs, as well as the addition of maintenance for new software purchases.
- Transfers to General Expenses Capitalized for 2016 were lower than 2015 primarily due to lower pension costs in 2016 compared to 2015.
- Conservation and Demand Management (CDM) amortization has increased from 2015. In 2013, the Board approved the deferred recovery, over a 7 year period, of annual costs associated with expansion of customer energy conservation programming. Amortization of this deferral commenced in 2014 and is higher in 2016 due to the inclusion of the third year of deferred customer energy conservation programming costs.

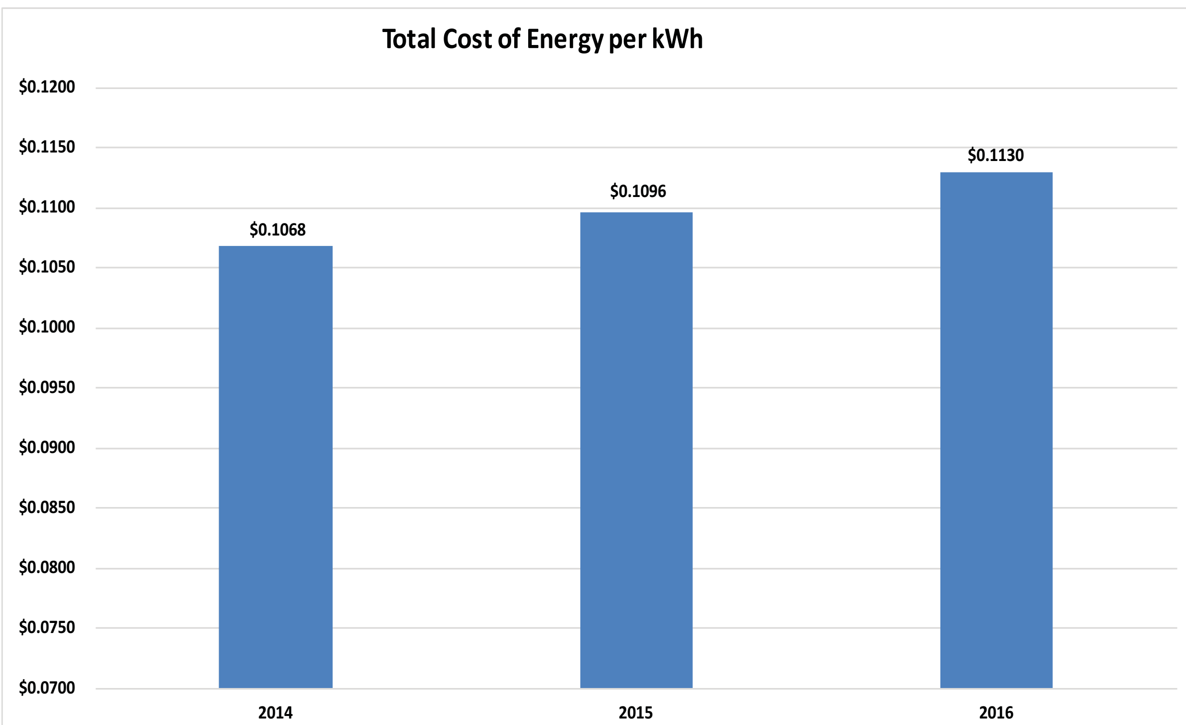
Other Costs

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 2014 to 2016:

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
2014	5,898,500	$ 83,972	$ 402,843	$ 3,990	$ 53,882	$ 36,450	$ 10,795	$ 37,840	$ 629,772	$ 0.1068
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



Purchased Power

We have reviewed the Company's purchased power expense for 2016 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 $21.2 million, from $422.1 million in 2015 to $443.3 million in 2016. According to the Company, the increase resulted primarily due to the interim wholesale rate increase which was effective July 1, 2015. The impact of this rate increase was partially offset by a reduced volume of wholesale 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 2016 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 2016; and,
- assessed the overall reasonableness of the depreciation for 2016.

Amortization expense for 2016 is $60,472,000 as compared to $56,720,000 for 2015, representing a 6.6% increase. The 2016 and 2015 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)	**2016**	**2015**	**Variance 2016-2015**	**%**
Depreciation and amortization as reported	$ 60,472	$ 56,720	$ 3,752	**6.6%**
Less: Tax on Cost of Removal (1)	(5,282)	(4,869)	(413)	**8.5%**
Depreciation of Fixed Assets	$ 55,190	$ 51,851	$ 3,339	**6.4%**

Note 1: Recognized as income tax for financial reporting purposes

The following table provides a comparison of the depreciation of fixed assets for 2016, 2015 and 2014:

($000's)	**2016**	**2015**	**2014**	**Variance 2016-2015**
Depreciation of Fixed Assets	$ 55,190	$ 51,851	$ 49,288	$ 3,339

Depreciation of fixed assets for 2016 is $55,190,000 as compared to $51,851,000 for 2015, representing a 6.4% increase. The change is attributable to an increase of depreciable assets by approximately $75,431,000.

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 2016.

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 2014 to 2016:

(000's)	Actual 2016	Actual 2015	Actual 2014	Variance 2016-2015
Interest				
Long - term debt	$ 34,846	$ 35,020	$ 36,327	$ (174)
Other	878	1,139	645	(261)
Amortization				
Debt discount	223	242	254	(19)
Interest charged to construction	(712)	(677)	(776)	(35)
Total Finance charges	$ 35,235	$ 35,724	$ 36,450	$ (489)
Year over year percentage change	-1.37%	-1.99%	0.04%	

In the above table, finance charges decreased by approximately $0.5 million, from $35.7 million in 2015 to $35.2 million in 2016. The lower finance costs reflect interest savings associated with the maturity of $30.4 million, 10.9% first mortgage sinking fund bonds on May 2, 2016, as well as lower short-term borrowings and related interest charges in 2016. These savings were partially offset by interest costs associated with the $75 million, 4.446% first mortgage bonds issued in September 2015.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2016 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 21.7% in 2015 to 22.6% in 2016. 2016, 2015 and 2014 results in the following effective rates:

	2016	2015	2014	2016-2015
Income tax expense	$ 11,851	$ 10,925	$ 10,795	$ 926
Earnings before income tax	$ 52,359	$ 50,239	$ 48,635	$ 2,120
Effective income tax rate	22.6%	21.7%	22.2%	0.9%

The effective rate increased by 0.9% in 2016 compared to 2015 primary due to a statutory tax rate increase of 1% in 2016. The Government of Newfoundland and Labrador increased the statutory tax rate from 29% to 30% effective January 1, 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 2016 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 $349,974 for the current period compare to a total of $345,837 for the same period during the previous year. Changes to the curtailment credits year over year are attributable to variation in demand and consumption, and the mix of Option participants achieving full or partial credit.

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

Non-Regulated Expenses

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

* assessed the Company's compliance with Board Orders;
* compared non-regulated expenses for 2016 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2016 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 2016	Actual 2015	Actual 2014	Variance 2016-2015
Charged from Fortis Companies	**2,249,100**	1,672,000	1,990,700	577,100
Performance and restricted share units	**454,500**	276,800	147,400	177,700
Donations and charitable advertising	**283,300**	273,700	331,100	9,600
Executive short term incentive	**341,000**	272,600	285,200	68,400
Miscellaneous	**70,200**	39,100	46,500	31,100
	3,398,100	2,534,200	2,800,900	863,900
Less: Income Taxes	**1,019,400**	734,900	812,200	284,500
Total non-regulated (net of tax)	**$ 2,378,700**	$ 1,799,300	$ 1,988,700	$ 579,400

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 2016 this represents an addition to non-regulated expenses (before tax adjustment) of $341,000 (2015 - $272,600). 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 2016 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 2015 and 2016:

(000's)	2016 Actual	2015 Actual	Variance 2016-2015
Regulatory Assets			
Rate stabilization account	**$ 4,763**	**$ 960**	$ 3,803
OPEBs asset	**31,536**	**35,040**	(3,504)
Deferred GRA costs	**682**	**-**	682
Conservation and demand management deferral	**15,999**	**10,511**	5,488
Optional seasonal rate revenue and cost recovery account	**-**	**60**	(60)
Employee future benefits	**100,757**	**113,044**	(12,287)
Weather normalization account	**2,458**	**6,212**	(3,754)
Deferred income taxes	**191,313**	**179,532**	11,781
	$347,508	**$345,359**	$ 2,149
Regulatory Liabilities			
Cost recovery deferral	**$ 2,064**	**$ -**	$ 2,064
Future removal and site restoration provision	**143,419**	**139,700**	3,719
Excess earnings	**-**	**68**	(68)
	$145,483	**$139,768**	$ 5,715

<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, 2016 were approved by the Board in Order No. P.U. 25 (2016).

As of December 31, 2016, there was a charge to the RSA of $3,134,800 related to the Energy Supply Cost Variance Reserve in accordance with Order No. P.U. 32 (2007) and Order No. P.U. 43 (2009).

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, 2016, there was a balance of $Nil in this account as the actual pension expense and forecast pension expense for 2016 were equal; therefore, no transfer to the RSA was necessary.

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, 2016, there was a balance of $Nil in this account as the actual pension expense and forecast pension expense for 2016 were equal; therefore, no transfer to the RSA was necessary.

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, 2016 $6,212,027 was debited 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), the Optional Seasonal Rate Revenue and Cost Recovery Account, 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 $171,000 incurred in 2016.

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, 2016 were $15,999,000 with amortization of $1,711,951 in 2016.

Optional Seasonal Rate Revenue and Cost Recovery Account

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with Order No. P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with Order No. P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2015 was $69,298. This balance was transferred to the RSA on March

31, 2016 pursuant to the Board's approval in Order No. P.U. 10 (2016). There was no balance in this account as at December 31, 2016.

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, 2016 the regulated asset for employee future benefits was $100,757,000

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. 12 (2017) the Board approved the December 31, 2016 net regulatory asset balance in the Weather Normalization Account of $2,458,000 ($1,720,705 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, 2016 was $191,313,000.

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 amortization of approximately $516,000, resulting in a net regulatory liability of $2,064,000 at December 31, 2016.

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 2016 the balance in this account was $143,419,000 (2015 - $139,700,000).

Excess earnings

Excess earnings are the earnings that exceed the upper limit of the allowed range of return on rate base of 7.39% approved by the Board in Order No. P.U. 25 (2016) for 2016 and 7.68% approved by the Board in Order No. P.U. 51 (2014) for 2015. For 2016 and 2015 the Company's regulated earnings did not exceed the upper limit and therefore there is $Nil excess earnings reported on the 2016 Return 13.

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2016 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 actual pension expense and the test year forecast pension expense for 2016 were equal; therefore, the balance in the PEVDA for 2016 is $Nil.

We confirm that the 2016 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 actual OPEBs expense and the test year forecast OPEBs expense for 2016 were equal; therefore, the balance in the OPEBVDA for 2016 is $Nil.

We confirm that the 2016 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 2016 are as follows:

1. Made capital investments of $96 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 and the Substation Modernization Plan.

4. The Company now has over 85% Automated Meter Reading ("AMR") penetration Island-wide. In 2016, over 51,000 AMR meters were installed. Route optimization resulted in the elimination of 171 routes by the end of 2016. This enabled meter reading labour cost savings of approximately $0.5 million compared to 2015.

5. Substantial progress was made in collecting customer and asset location data. Approximately 86% of customer connectivity data and 72% of distribution line phasing data has been compiled in the Company's Geographic Information System ("GIS"). The project is scheduled for completion in the first quarter of 2017.

6. Continued the Substation Modernization and Refurbishment program in total 75% of the distribution feeders are now automated.

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

8. During the 4th quarter, the Company implemented a lone worker monitoring solution using a Telelink smart phone application. The technology initiates regular check-ins to monitor employees exposed to medium or high risk hazards who are working alone on the job. Where cell phone service is unavailable workers carry satellite enabled devices.

9. The Company's electronic billing program grew to over 100,000 accounts in 2016, representing approximately 40% of customer accounts.

10. Customer self-service results for 2016 are 85%, above the plan and 2015. Self-service usage continues to show improvement. There was a 56% increase in online outage reporting, a 40% increase in online streetlight reporting and a 30% increase in website payment arrangements.

11. A new virtual agent technology was introduced as a pilot project in the Company's regional offices. The pilot will enable customers to directly video/audio link to a Customer Service Representative in the Contact Centre in St. John's when the regional office is fully tasked. The customer will be able to sign contracts, show IDs, and will be able to complete all regular customer service functions with this virtual agent.

12. The Company launched an automated outbound phone call technology, called Robocall, to improve customer communications and assist operations with restoration during an extended power outage on the south west coast of the island in December. The automated outbound phone calls reached over 80% of customers within seconds. The messages provided information about topics such as estimated restoration times, energy conservation, safety, and warming centers.

13. Newfoundland Power launched a smartphone app which will provide an easy and convenient way for customers to connect with the Company. Customers will be able to view their account information, access up to date information on power outages and report an outage using the app.

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 provided by Newfoundland Power lists the principal performance measures used in the management of the Company:

Category	Measure	Actual 2014	Actual 2015	Actual 2016	Plan 2016	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.93	2.36	2.24	2.36	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	2.44	2.11	1.36	1.87[5]	Yes
	Plant Availability (%)	94.4	94.9	93.2[3]	95.0	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	83.5	86.0	86.0	87.0	No
	Call Centre Service Level (% per second)	80/60	82/60	81/60[4]	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	81.0	86.0	87.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	1.2	0.5	1.3	0.9	No
Financial	Earnings (millions)	$37.3	$38.8	$40.0	$38.3	Yes
	Gross Operating Cost/Customer[2]	$259	$249	$260	$260	Yes

[1] 2014 reliability statistics above exclude the impact of the January Newfoundland and Labrador Hydro (NLH) system problems. 2016 reliability statistics exclude the impact of a wind storm in December.
[2] Excludes pension, OPEBs and early retirement costs.
[3] 93.1 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved.
[4] 82/60 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved.
[5] 1.93 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved.

The following table compares whether the company measures were achieved during the 2014, 2015, and 2016 years:

Category	Measure	Measure Achieved 2014	Measure Achieved 2015	Measure Achieved 2016
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	No	Yes	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	No	No	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 (%)	No	Yes	Yes
Safety	All Injury/Illness Frequency Rate	Yes	Yes	No
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	No	Yes	Yes

Grant Thornton
2017 Annual Financial Review of Newfoundland Power Inc.

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.

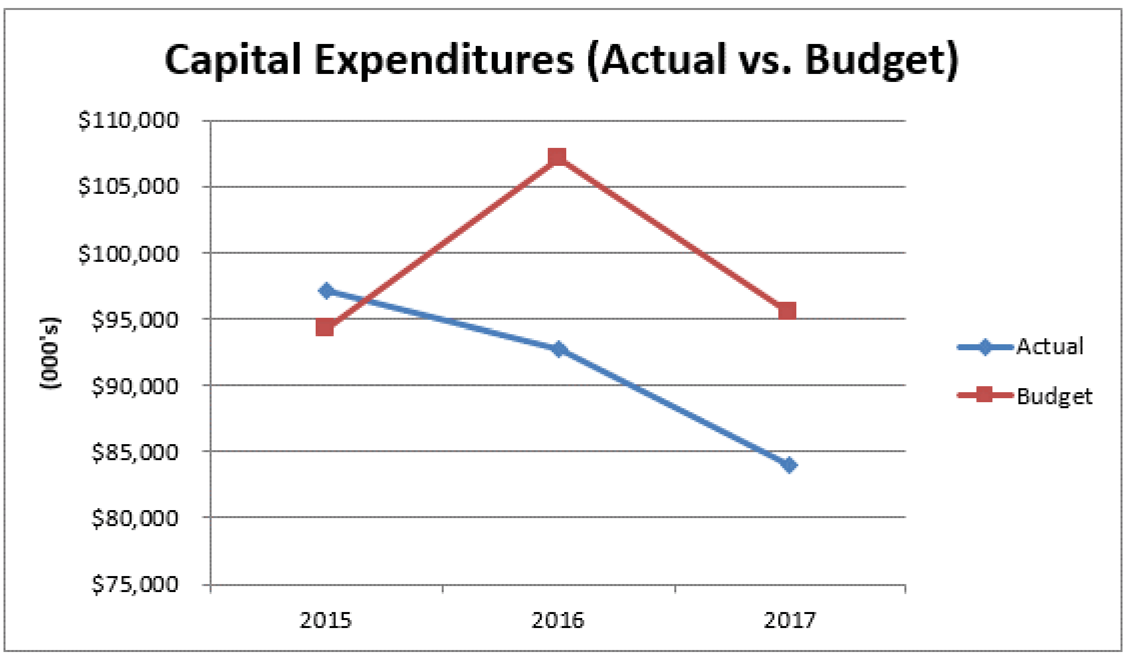
Capital Expenditures

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

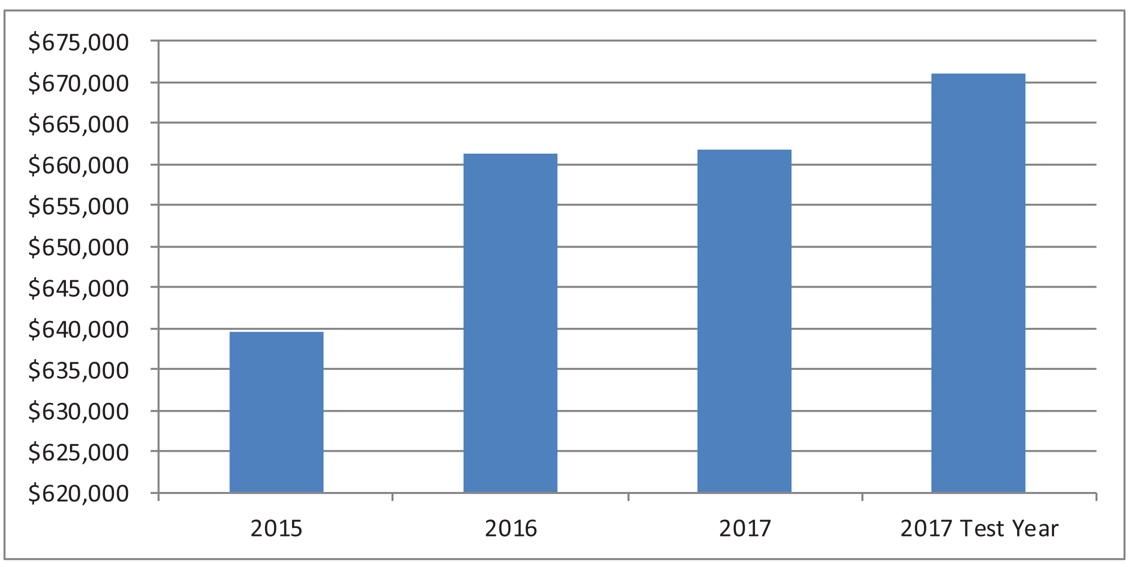
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2017 calendar year.

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.

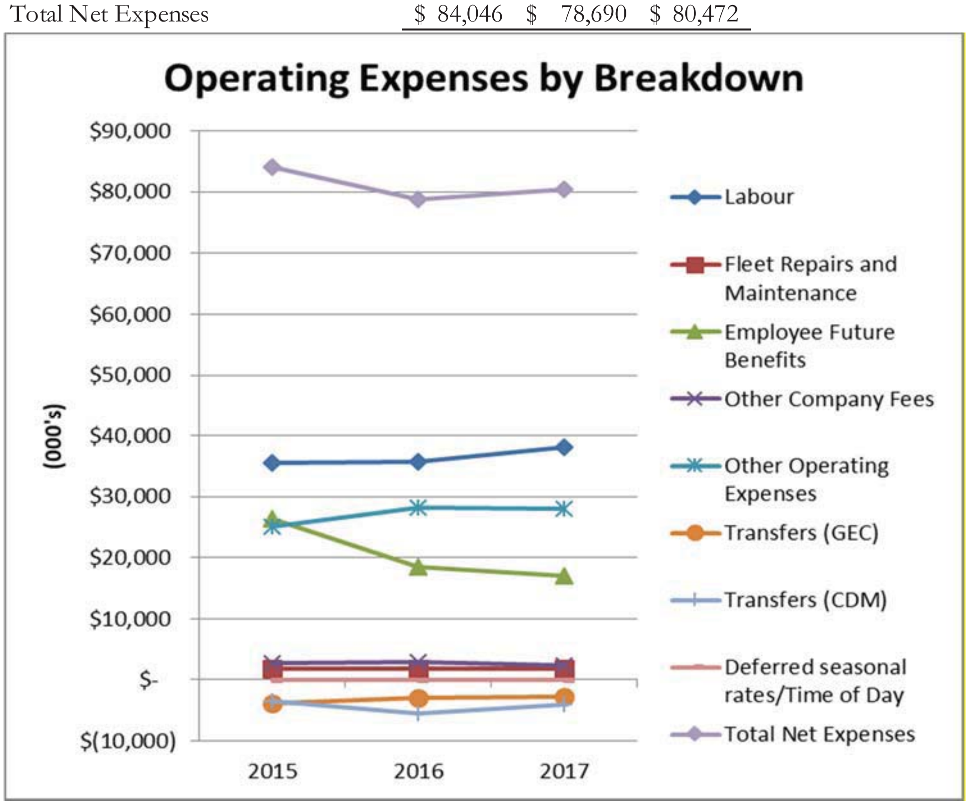
(000's)	Actual 2017	Test Year 2017	Actual 2016	Actual 2015	Variance Actual-Test	Variance 2017-2016
Labour	$ 39,341		$ 36,770	$ 36,485	$ -	$ 2,571
Reclass OPEB labour cost	(1,173)		(981)	(969)	-	(192)
Total Labour	38,168	37,956	35,789	35,516	212	2,379
Vehicle expense	1,854	1,586	1,797	1,786	268	57
Operating 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.

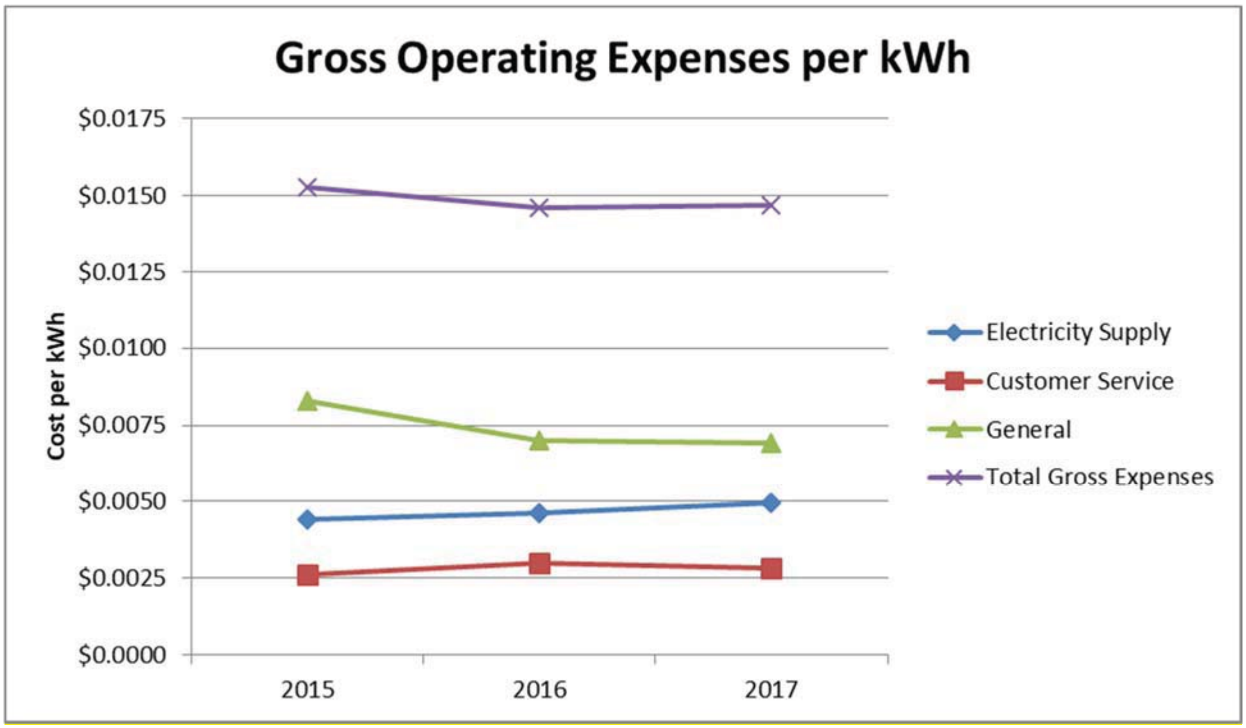
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the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

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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.

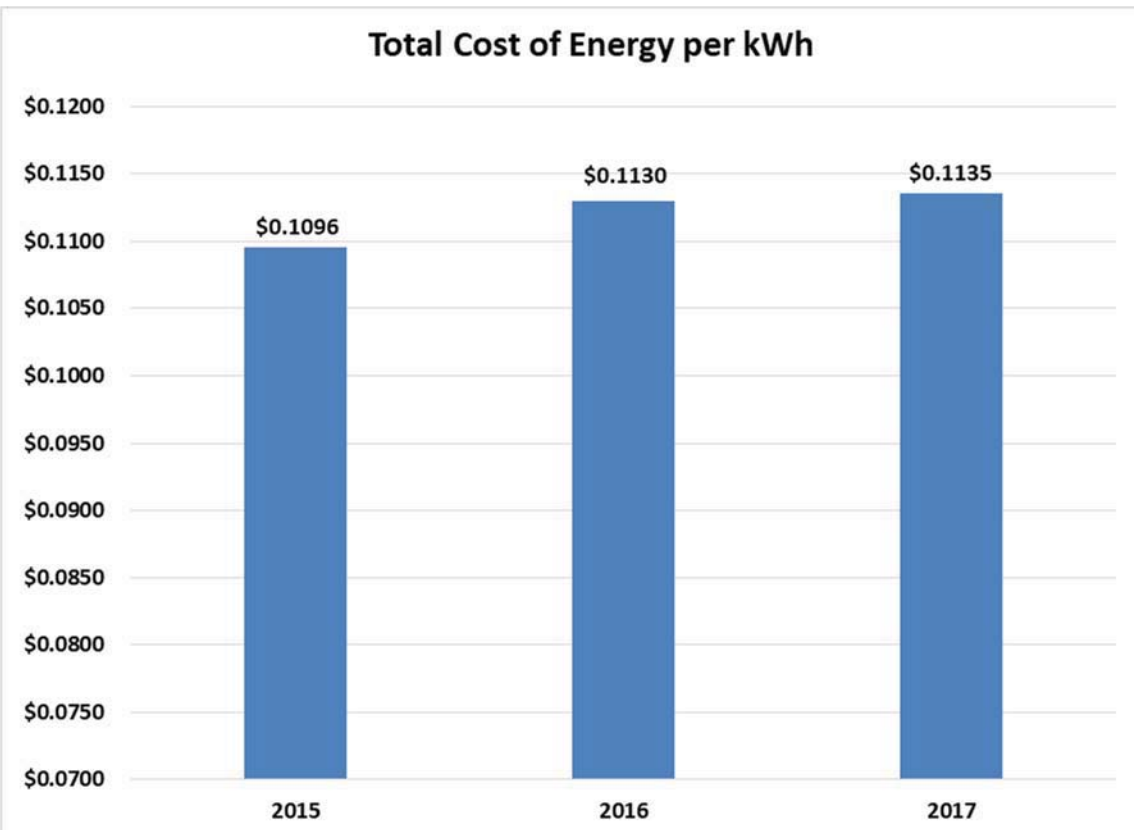
Other Costs

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

__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. 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

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Restrictions, Qualifications and Independence

Purpose

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

Restrictions and Limitations

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

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

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

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

Executive Summary

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

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

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

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

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

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

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

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

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

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

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

Introduction

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

Scope and Limitations

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

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

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

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

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

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

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

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

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

7. Review Minutes of Board of Directors' meetings.

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

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

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

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

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

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

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

The financial statements of the Company for the year ended December 31, 2018 have been audited by Deloitte LLP, Chartered Professional Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 14, 2019. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

System of Accounts

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

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

On March 29, 2019, the Company filed a revised system of accounts as part of its 2018 Annual Report. In submitting these changes, the Company noted that the revisions were mainly due to accounts approved by the Board over the last two years.

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

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

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

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

Our procedures with respect to verifying the calculation of the average rate base were directed towards the verification of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

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

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

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

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

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

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

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

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

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

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

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

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

Transfer to RSA:

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

Other transfers:

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

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

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

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

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

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

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

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

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

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

Return on Average Rate Base

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

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

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

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

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

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

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

Capital Structure

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

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

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

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

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

Calculation of Average Common Equity and Return on Average Common Equity

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

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

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

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

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

Interest Coverage

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

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

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

In Order No. P.U. 43 (2009) the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. The level of interest coverage realized for 2018 is 2.4 times.

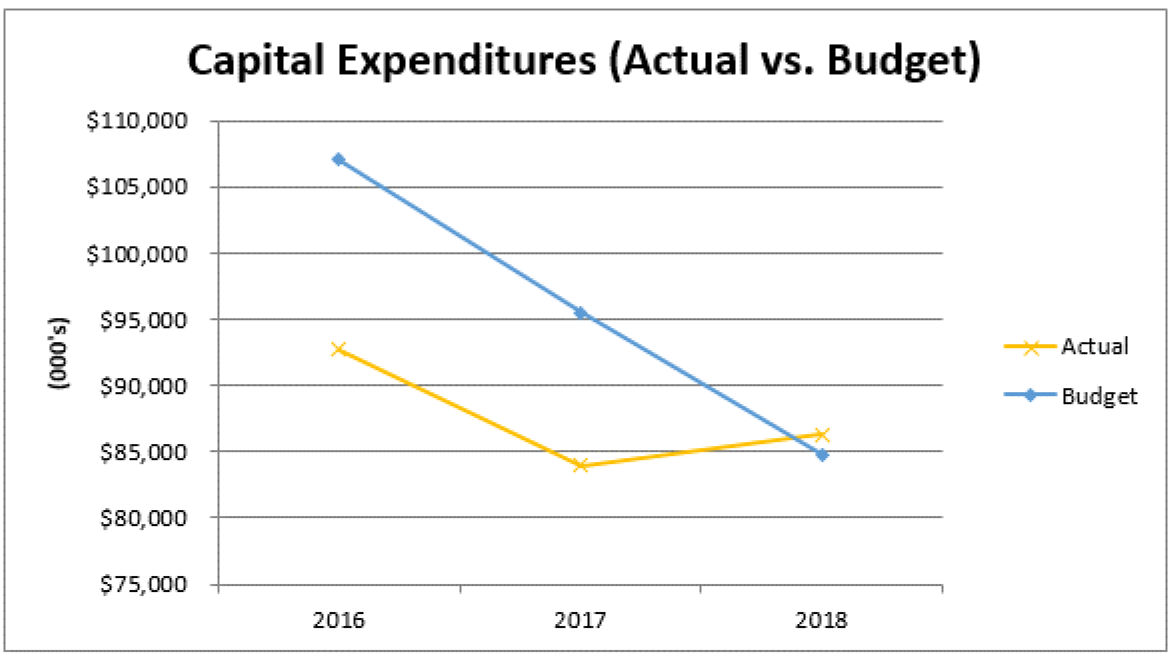
Capital Expenditures

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

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

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

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



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

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

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

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

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

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

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

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

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

Adherence to Capital Budget Application Guidelines

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

- Under Section A, as required, the Company filed its annual capital budget application by July 15th and followed appropriate guidelines for the format of the application submitted.
- Under Section C, as required, the Company filed its annual capital expenditures report by the deadline of March 1st and included within its explanations of variances greater than both $100,000 and 10%.
- Section C of the guidelines also notes that "should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered". This is interpreted to refer to the variance exceeding 10% in two consecutive years. The variance was -12.14% in 2017 and 1.78% in 2018 resulting in no additional reporting requirements.

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

Capital Expenditure Reports

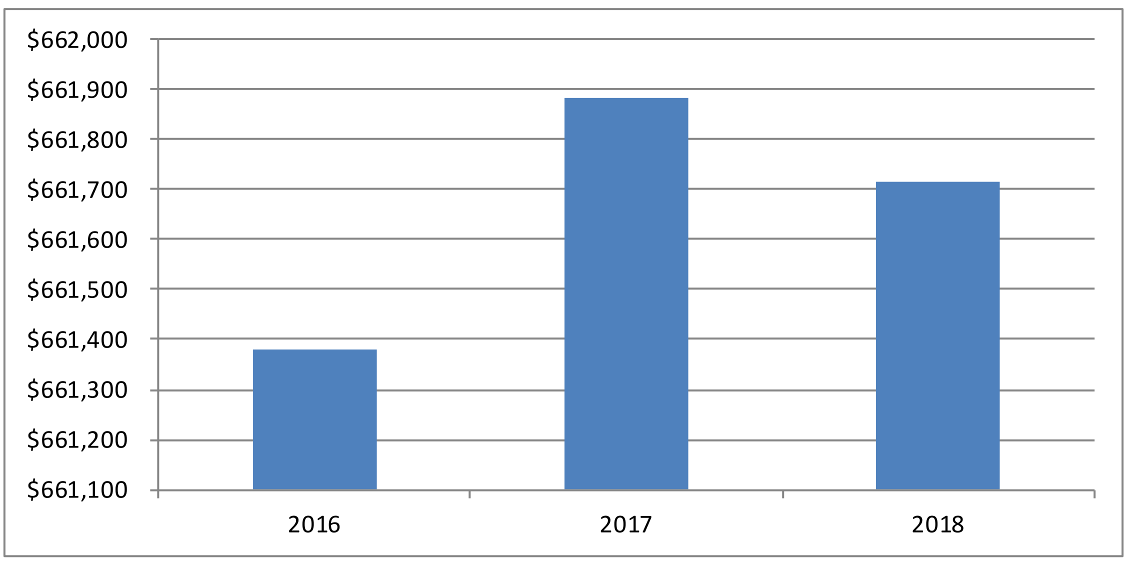
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2018 calendar year.

Revenue from rates

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

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

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



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

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

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

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

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

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

Operating and General Expenses

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

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

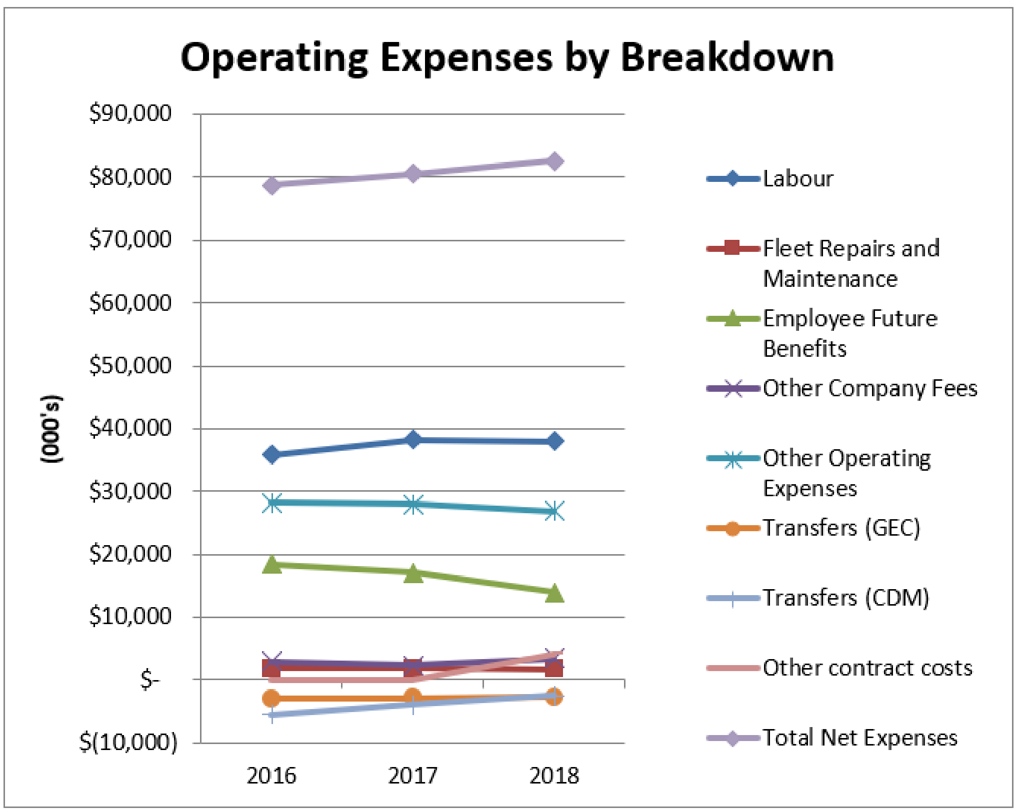
Note 1: According to the company, the presentation of other revenue was changed to be on a gross basis in 2018. This resulted in an increase in revenue and operating costs in 2018 related to work for telecommunciation companies. The 2017 and 2016 comparative have not been restated for this change in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

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

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

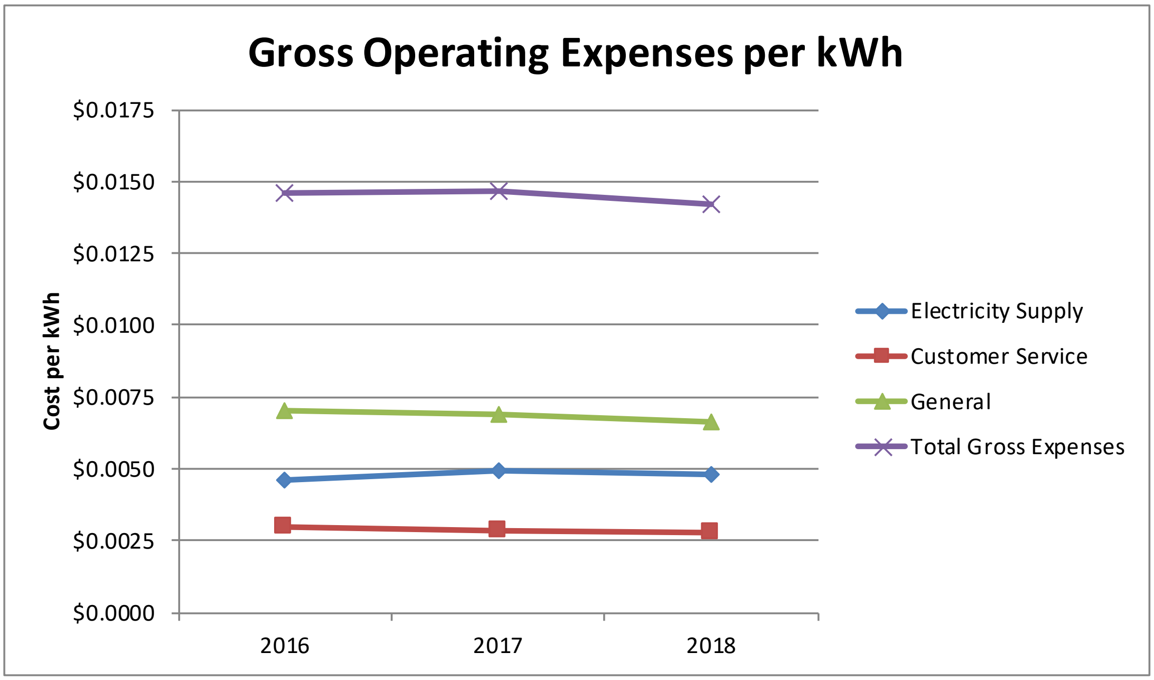
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in operating expenses by breakdown for the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

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



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

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



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

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

Salaries and Benefits (including executive salaries)

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

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

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

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

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

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

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

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

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

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

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

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

Short Term Incentive (STI) Program

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Executive Compensation

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

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

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

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

Company Pension Plan

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

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

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

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in Order No. P.U. 7 (1996-97) that the pension uniformity plan is allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses decreased by 12.12% in 2018.

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

Other Post-Employment Benefits ("OPEBs")

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

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

The components of OPEBs expense for 2016 to 2018 are as follows:

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

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

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

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

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

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

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

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

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

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

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

2018 Recoverable Expenses from Fortis Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Other Company Fees and Deferred Regulatory Costs

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

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

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

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

Miscellaneous

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

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

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

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

Conservation and Demand Management (CDM)

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

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

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

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

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

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

Other Operating and General Expense Categories

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

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

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

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

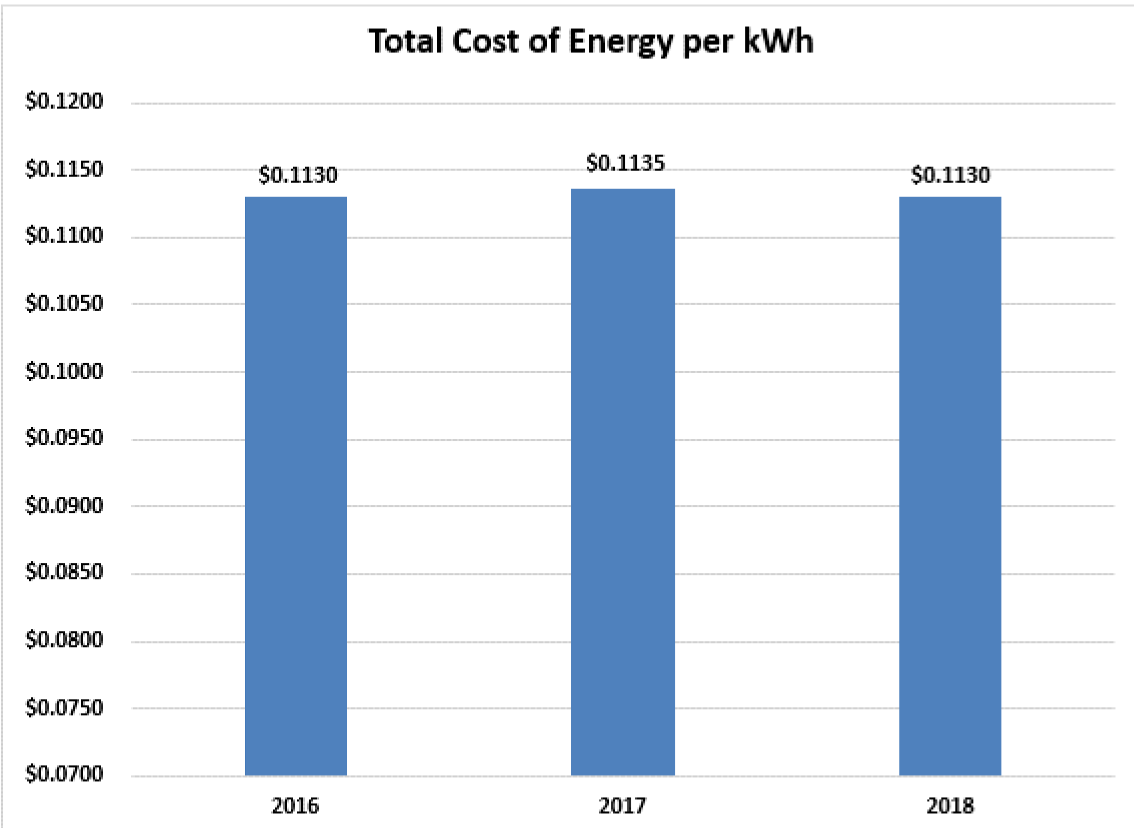
Other Costs

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

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

000's

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



Purchased Power

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

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

Depreciation

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

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

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

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

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

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

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

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

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

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

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

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

Finance Charges

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

The following table summarizes the various components of finance charges expense for the years 2016 to 2018:

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

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

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

Income Tax Expense

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

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

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

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

Costs Associated with Curtailable Rates

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

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

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

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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

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. 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

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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.

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Restrictions, Qualifications and Independence

Purpose

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

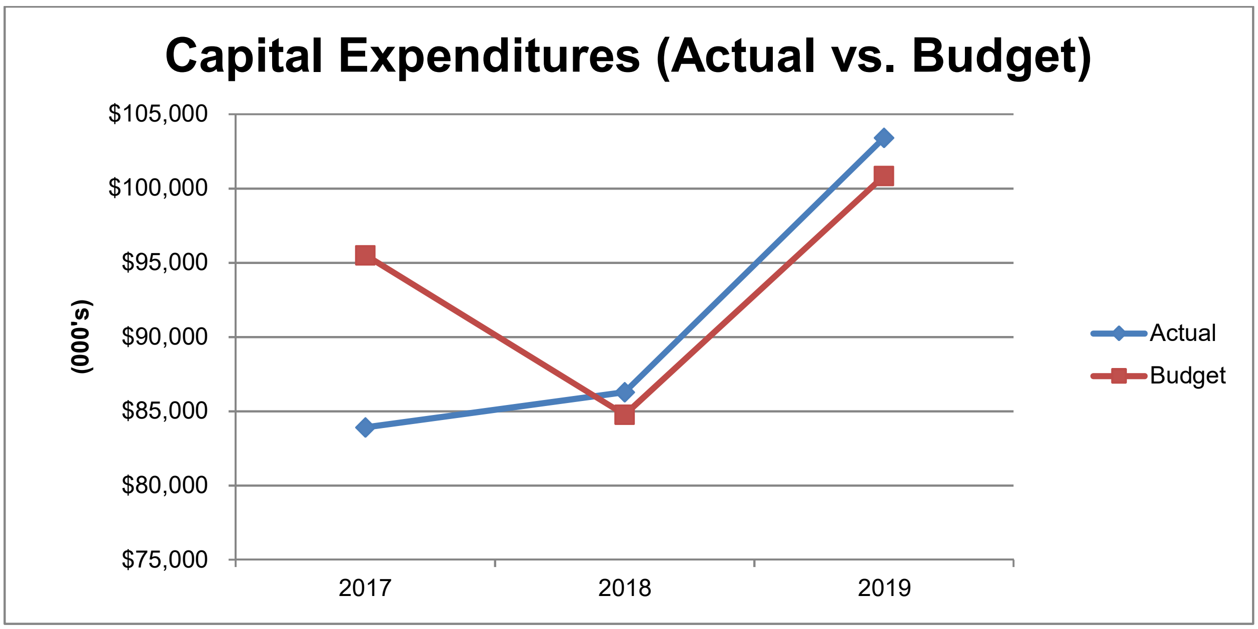
Capital Expenditures

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.



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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.

Capital Expenditure Reports

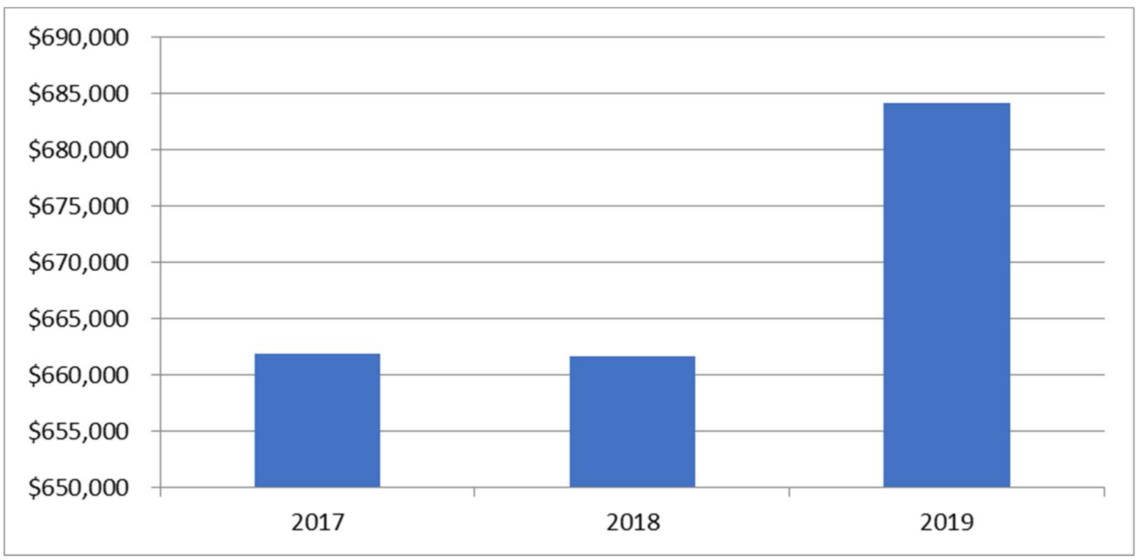
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2019 calendar year.

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.***

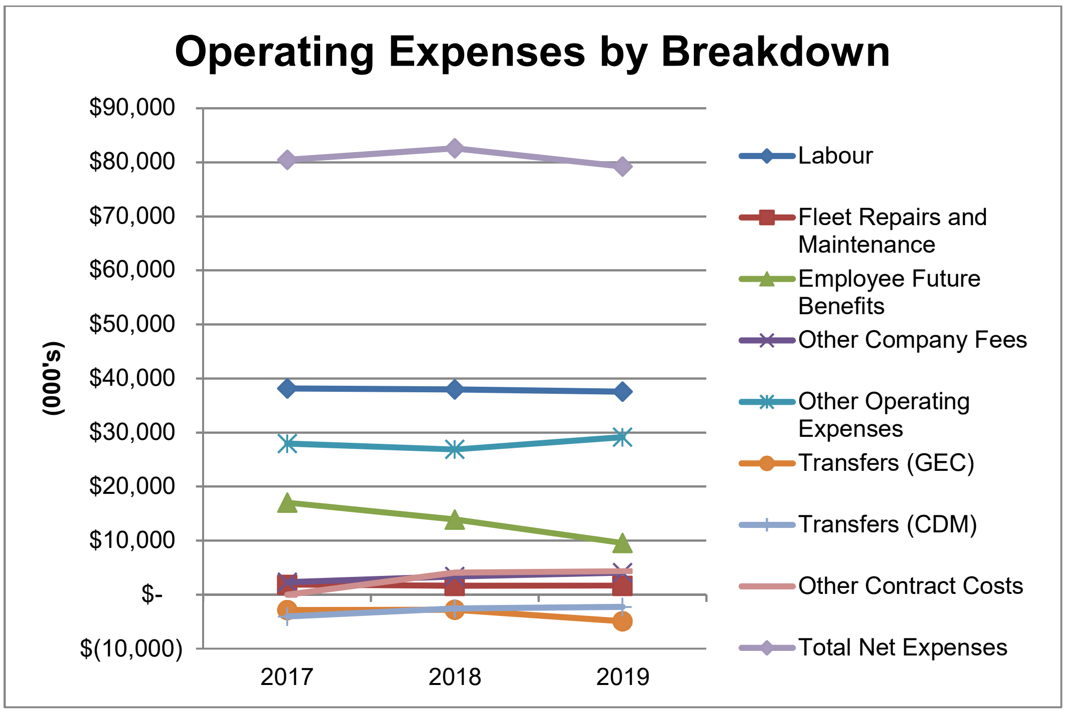
(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Labour	$ 38,603	$ 39,095	$ 39,341	$ (492)
Reclass OPEB labour cost	(1,041)	(1,125)	(1,173)	84
Total Labour	37,562	37,970	38,168	(408)
Vehicle expense	1,681	1,682	1,854	(1)
Operating materials	1,361	1,511	1,528	(150)
Inter-company charges	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.

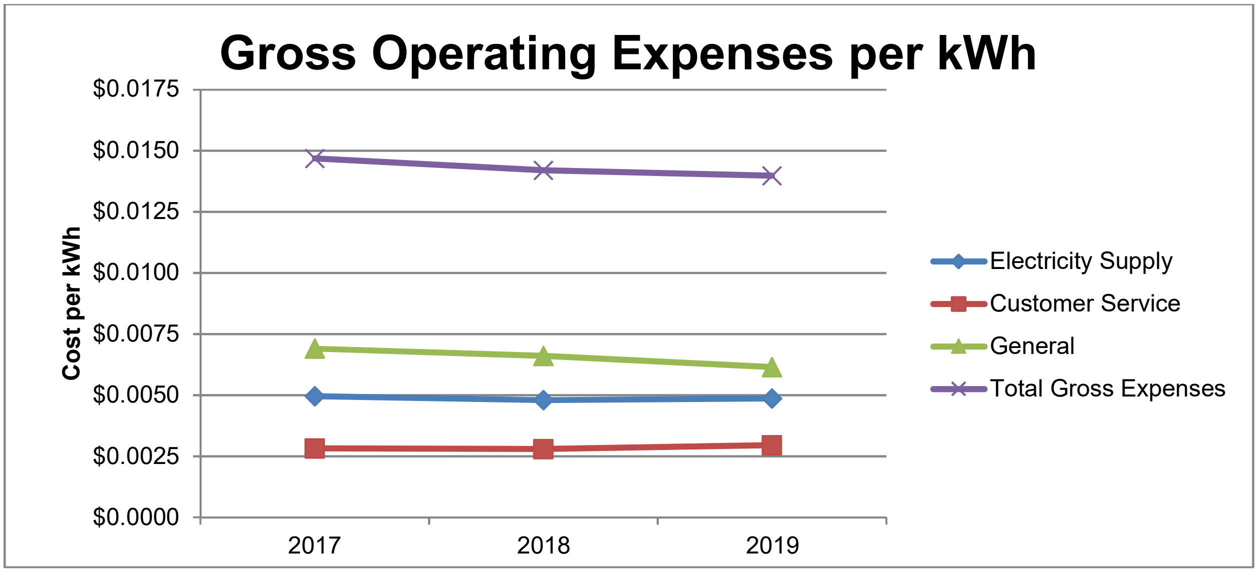
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in operating expenses by breakdown for the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

1 The following table provides a summary and comparison of the other intercompany transactions for 2017 to 2019:
2

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

3

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.

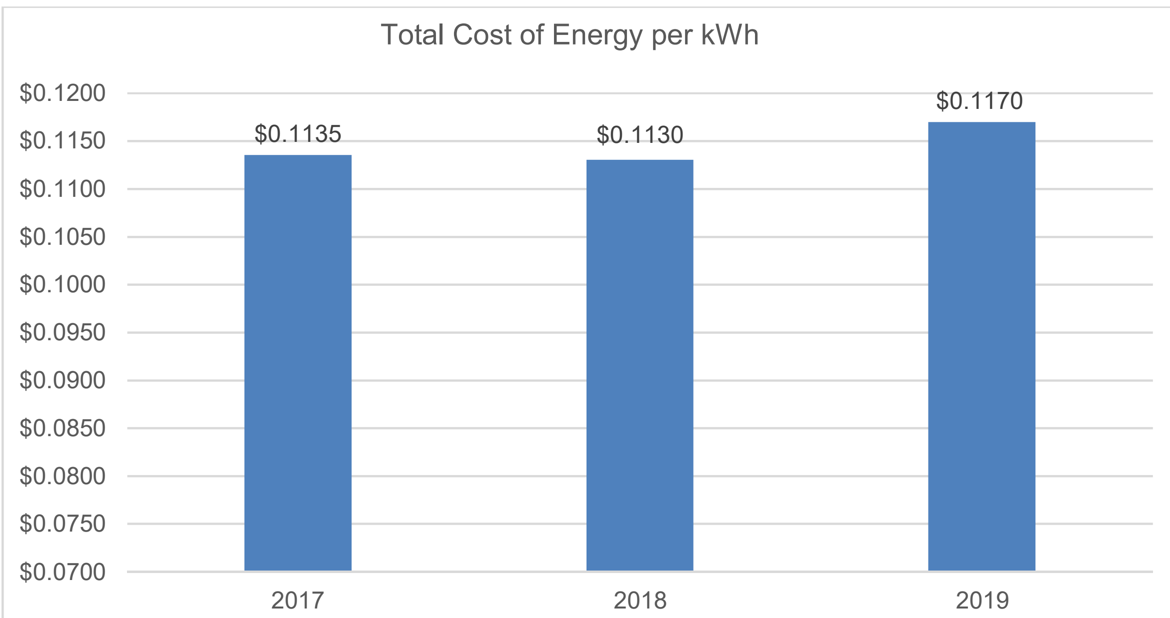
Other Costs

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