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.

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 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.

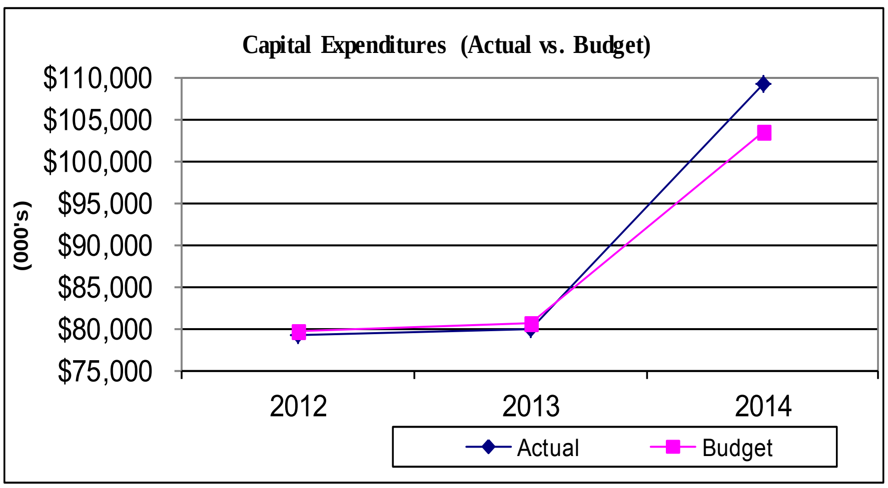
Capital Expenditures

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.

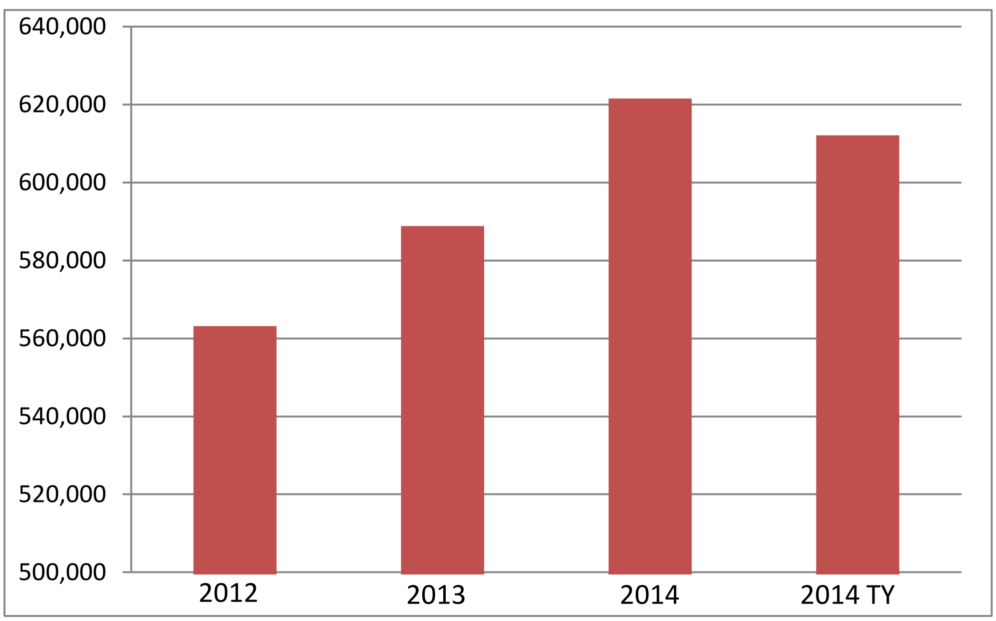
Revenue

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.

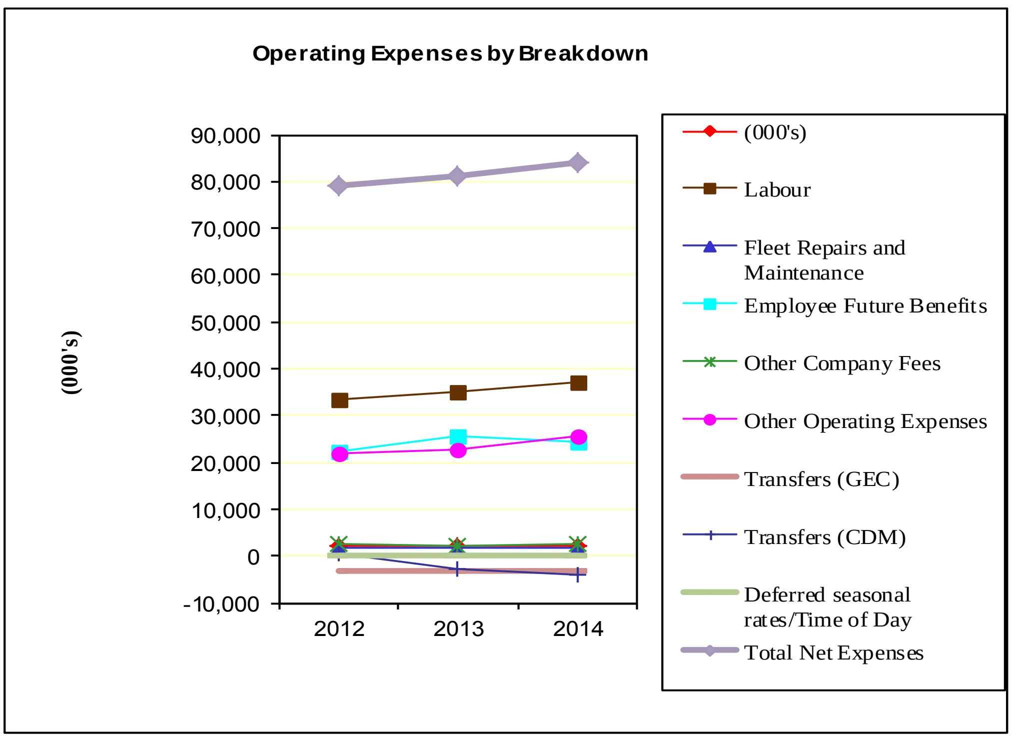
(000's)	2014 Actual	2014 Test Year	2013 Actual	Variance Actual - Test	Variance 2014 - 2013
Labour	$ 37,871	$ 36,376	$ 35,918	$ 1,495	$ 1,953
Reclass OPEB labour cost	(658)	(600)	(663)	(58)	5
Total Labour	37,213	35,776	35,255	1,437	1,958
Vehicle expense	1,901	1,898	1,881	3	20
Operating materials	1,857	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.

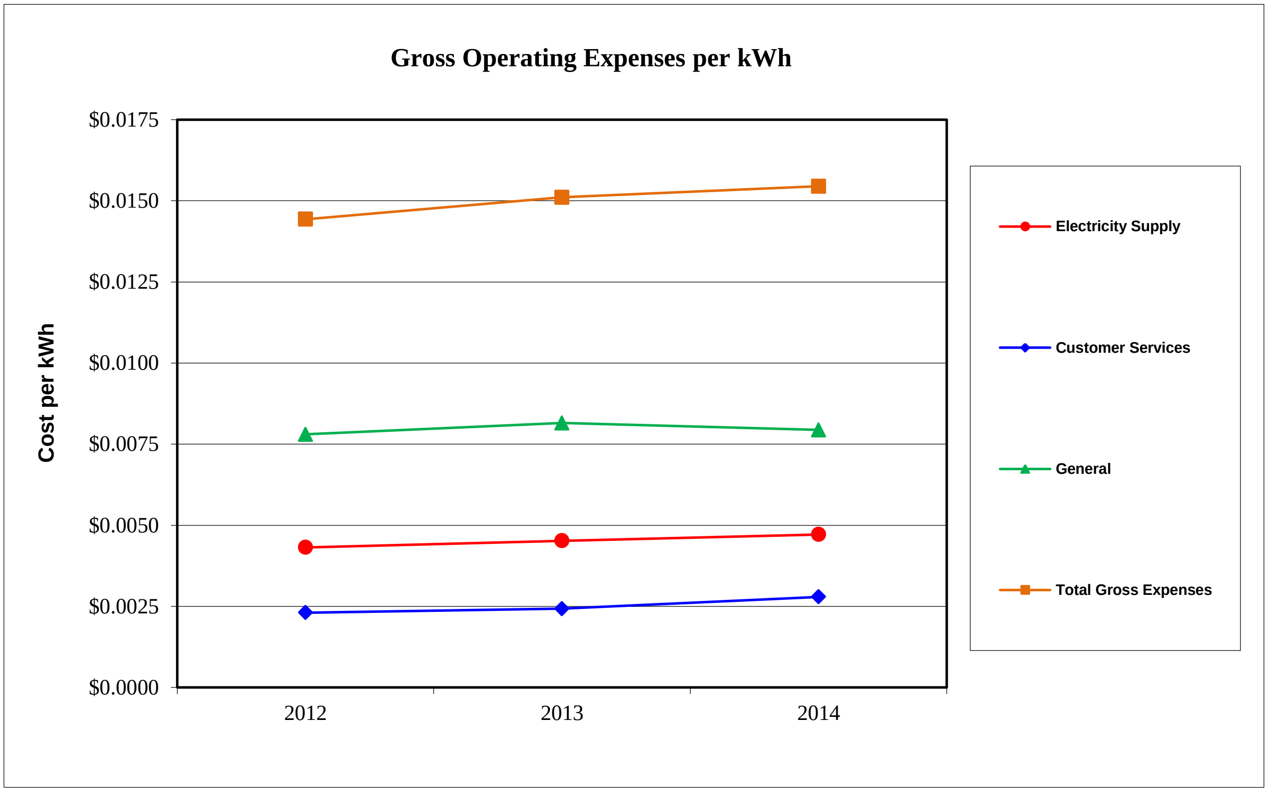
	Actual		
(000's)	**2012**	**2013**	**2014**
Labour	$ 33,549	$ 35,255	**$ 37,213**
Fleet Repairs and Maintenance	1,827	1,881	**1,901**
Employee Future Benefits	22,170	25,624	**24,244**
Other Company Fees	2,488	2,024	**2,650**
Other Operating Expenses	21,788	22,608	**25,418**
Transfers (GEC)	(3,120)	(3,415)	**(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.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 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%

STI actual payout rates for ‘president’, ‘executive’ and ‘manager’ employee groups are lower than in the prior 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 Fortis BC 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 Fortis BC 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

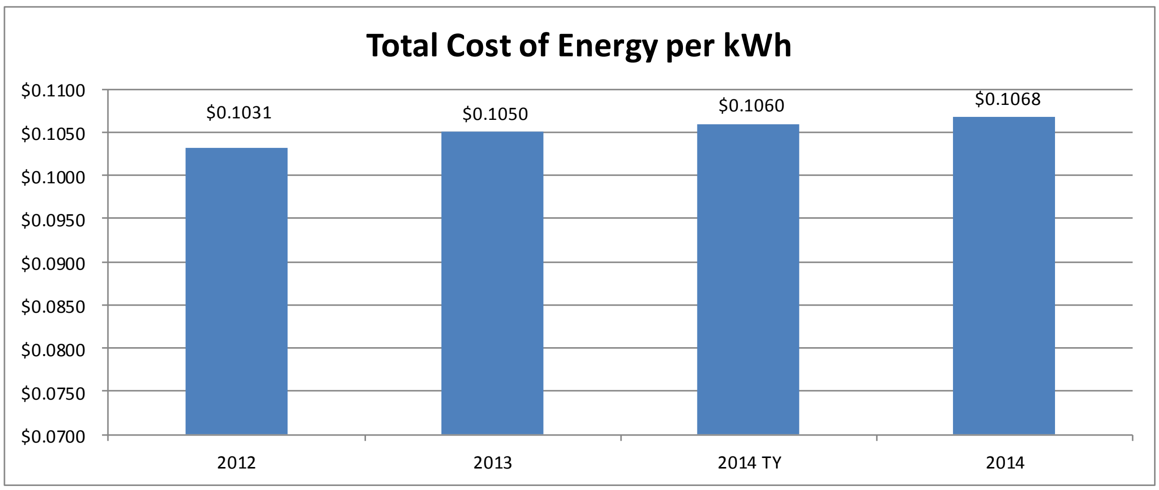
Scope: ***Conduct an examination of purchased power, depreciation, interest and income taxes to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

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.

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 $176,707,000.

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 ($5,020,00 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