Grant Thornton
2013 Annual Financial Review of Newfoundland Power Inc.

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

Contents

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Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2013 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"). Below is a summary of the key observations and findings included in our report.

The average rate base for 2013 was $915,820,000 compared to average rate base for 2012 of $883,045,000 and 2013 Test Year of $918,716,000. The Company's calculation of the return on average rate base for 2013 was 8.10% (2012 - 8.10%) compared to an approved rate of return of 7.92%. The actual rate of return was the maximum of the range approved by the Board (7.74% to 8.10%). The calculations of average rate base and rate of return on average rate base are in accordance with established practice and Board orders.

The Company's calculation of average common equity for 2013 was $414,578,000 (2012 - $395,793,000). The Company's actual return on average common equity for the year ended December 31, 2013 was 9.16% (2012 – 8.98%). In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2013 the cost of common equity per the Formula was 8.8% (P.U. 13 (2013)). The actual return on average common equity for 2013 was 9.16% as noted above. This return was within the 50 basis point trigger and as such no report was required.

The actual capital expenditures (excluding capital projects carried forward from prior years) was 0.96% under budget in 2013. The capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $2,544,000 (2.74%). However, for each category of expenditure, the variances ranged from an over-budget of 10.18% to an under-budget of 85.81%. Significant variances are explained in our report.

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

Net operating expenses in 2013 increased by $2,351,000 from 2012 and $3,009,000 over the 2013 Test Year. The increase is primarily due to an increase in labour, pension and the accrual of other post-employment benefits ("OPEBs"). These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2013 are unreasonable.

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

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

Based on our review, the 2013 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

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

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

The Company continues to undertake initiatives aimed at improving reliability of service and efficiency of operations as is summarized in the Section entitled 'Productivity and Operating Improvements'. During 2013 the Company met six out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Outage/Customer (SAIFI) – excluding Hydro loss of supply", "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey". The Company excluded the impact of the January Newfoundland and Labrador Hydro system problems and the November blizzard in Central and Western.

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Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2013 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

Scope and Limitations

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

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

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

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

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

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

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

5. Examine the Company's 2013 capital expenditures in comparison to budgets and prior years and follow up on any significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

6. Review the Company's rates of depreciation and assess their compliance with the Gannett Fleming Depreciation Study included in the 2013 GRA, and review the calculations of depreciation expense.

7. Review Minutes of Board of Directors' meetings.

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

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

10. Conduct an examination of the Pension Expense Variance Deferral Account to assess compliance with P.U. 43 (2009) and P.U. 16 (2013).

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

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

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

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

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

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

The financial statements of the Company for the year ended December 31, 2013 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 5, 2014. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

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System of Accounts

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

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

On March 28, 2014, the Company filed a revised system of accounts as part of its 2013 Annual Report. In submitting these changes the Company noted that the revisions were mainly due to accounts approved by the Board over the last two years.

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

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

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

Calculation of Average Rate Base

The Company's calculation of its average rate base for the year ended December 31, 2013 which is included on Return 3 of the annual report to the Board was computed using the Asset Rate Base Method ("ARBM"). The average rate base for 2013 was $915,820,000 compared to forecast average rate base for 2013 test year of $918,716,000 as approved during the 2013 GRA in P.U. 13 (2013). The decrease of $2,896,000 (0.32%) below test year is primarily a result of future income taxes below those forecasted. The average rate base for 2012 was $883,045,000.

Our procedures with respect to verifying the calculation of the average rate base were directed towards the verification of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including audited financial statements and internal accounting records, where applicable;
- agreed component data (capital expenditures; depreciation; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of the rate base for 2013; and
- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act to ensure it is in accordance with Board Orders and established policy and procedure.

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The following table summarizes the components of the average rate base for 2013, 2013 test year and 2012 (all figures shown are averages):

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

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(a) The Company's rate base is determined using the Asset Rate Base Method which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $100,756,000 (2012 - $99,125,000) included in the 2013 rate base consists of average deferred pension costs of $100,636,000 (2012 - $98,871,000) and credit facility costs of $120,000 (2012 - $255,000). The Company has included a schedule of these costs in Return 8.

(b) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to P.U. 8 (2011), "on December 31st of each year from 2011 until further order of the Board, this account shall be charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal – Optional and the Time-of-Day Rate Study". The calculation of the 2013 average rate base incorporates $94,000 (2012 - $160,000) related to this deferral account.

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

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

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

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

(g) In P.U. 43 (2009) the Board approved Newfoundland Power's proposal to recover the 2009 conservation programming costs of approximately $1,500,000 ($1,020,000 after tax) over the remaining four years of the 5-year Energy Conservation Plan. These costs were fully amortized in 2013. In P.U. 13 (2013) the Board approved Newfoundland Power's proposed change in definition of conservation program costs and the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. The actual costs incurred and deferred in 2013 were $2,937,000 ($2,085,000 after tax) with annual amortization of this

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amount of $298,000 to commence in 2014. Included in the calculation of the average rate base for 2013 is $1,156,000 related to this deferral.

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

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

Transfer to RSA

i. In P.U. 13 (2013) the Board approved annual balances in the Weather Normalization reserve be recovered from or credited to customers through the Rate Stabilization Account. This resulted in a transfer (increase) to the reserve of $216,000 in 2013.

Other transfers:

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

Amortization

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

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

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

(k) Customer Security Deposits are comprised of security deposits received from customers for electrical services in accordance with the Board-approved Schedule of Rates, Rules and Regulations. The calculation of the 2013 average rate base incorporates $846,000 (2012 - $773,000) related to customer security deposits.

(l) The 2013 average rate base calculation incorporates $4,173,000 (2012 - $3,899,000) of Accrued Pension Obligation. This obligation is a result of executive and senior management supplemental pension benefits comprised of a defined benefit plan and a defined contribution plan. The defined benefit plan was closed to new entrants in 1999.

(m) In P.U. 32 (2007) the Board approved the Company's adoption of the accrual method of accounting for income tax related to pension costs. In P.U. 31 (2010) the Board approved the Company's adoption of the accrual method of accounting for other post employment benefits (OPEBs) costs and income tax related to OPEBs. The balance of deferred income taxes related to pension costs and OPEBs included in the 2013 average rate base is $1,017,000 and ($5,202,000) respectively. The remaining balance of the deferred income tax liability in the amount of $6,373,000 relates to capital assets. This results in an average balance for deferred income tax liability of $2,188,000. The average test year balance for 2013 was ($1,877,000), a variance from actual of $4,065,000. The primarily reason for this variance relates to the difference in pension funding in 2012 with an actual of $15,970,000 in funding compared to test year forecast for 2012 of $5,363,000 in funding.

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

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

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

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

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

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

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

Other than the items previously discussed, we did not note any discrepancies in the calculation of the 2013 average rate base included in Return 3 of the Company's Annual Returns and we conclude that the average rate base of $915,820,000 is accurate and in accordance with established practice and Board Orders.

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Return on Average Rate Base

The Company's calculation of the return on average rate base is included on Return 13 of the annual report to the Board. The return on average rate base for 2013 (based on the revised average rate base of $915,820,000 filed in Schedule D of its 2015 Capital Budget Application) was 8.10% (2012 - 8.10%). Our procedures with respect to verifying the reported return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the rate of return to ensure it is in accordance with established practice and Board Orders. For 2013, the return on average rate base is calculated in accordance with the methodology approved in P.U. 13 (2013).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2011 to 2013 is set out in the table below.

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

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

As the rate of return on average rate base is outside the range set by the Board the Company has recorded a regulatory liability and decrease in earnings in the amount of $68,000 ($49,000 after tax). As a result of the revised average rate base we calculated excess earnings of $42,000 ($33,000 after tax). In discussions with the Company they have determined the additional excess earnings of $26,000 ($16,000 after tax) reported in Return 13 are immaterial to file a revised return. This represents a benefit to the customer. See 'Regulatory Assets and Liabilities' section of our report for further details.

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

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Capital Structure

In P.U. 13 (2013) the Board reconfirmed its previous position as per P.U. 43 (2009) regarding the capital structure for Newfoundland Power Inc. and the Board has deemed that the proportion of common equity in the capital structure shall not exceed 45%.

The Company's capital structure for 2013 as reported in Return 24 is as follows:

	2013 Average		**2012**	**2011**
	(000's)	**Percent**	Percent	Percent
Debt	**$504,185**	**54.35%**	54.47%	54.22%
Preferred equity	**9,031**	**0.97%**	1.02%	1.04%
Common equity	**414,578**	**44.68%**	44.51%	44.74%
	$927,794	**100.00%**	100.00%	100.00%

Pursuant to P.U. 32 (2007), the Company did submit a schedule (Return 25) calculating the cost of embedded debt for the current year. It also indicated the variances in interest expense and average debt over the 2013 test year in Return 26. The embedded cost of debt for 2013 was 7.24% which represents a 1 bps increase from 2013 test year embedded cost of debt of 7.23%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in compliance with Board Order P.U. 13 (2013).

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Calculation of Average Common Equity and Return on Average Common Equity

The Company's calculation of average common equity and return on average common equity for the year ended December 31, 2013 is included on Return 27 of the annual report to the Board. The average common equity for 2013 was $414,578,000 (2012 - $395,793,000). The Company's actual return on average common equity for 2013 was 9.16% (2012 – 8.98%).

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

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;
- agreed component data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of book common equity per P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007), P.U. 43(2009) and P.U. 13 (2013).
- recalculated the rate of return on common equity for 2013 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 13 (2013).

In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2013 the cost of common equity was 8.80% as per P.U. 13 (2013). The actual return on average common equity for 2013 was 9.16% as noted above. This return was within the 50 basis point trigger and as such no report was required.

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

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Interest Coverage

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

(000's)	**2013**	2012
Net income	**$ 49,920**	$ 37,204
Income taxes	**(2,877)**	10,861
Interest on long term debt	**35,123**	35,039
Interest during construction	**(893)**	(820)
Other interest and amortization of debt discount costs	**1,377**	1,258
Total	**$ 82,650**	$ 83,542
Interest on long term debt	**$35,123**	$ 35,039
Other interest and amortization of debt discount costs	**1,377**	1,258
Total	**$36,500**	$ 36,297
Interest Coverage (times)	**2.3**	2.3

The above table shows that the interest coverage did not change from 2012 to 2013.

In P.U. 43 (2009) the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. The level of interest coverage realized for 2013 is 2.3 times.

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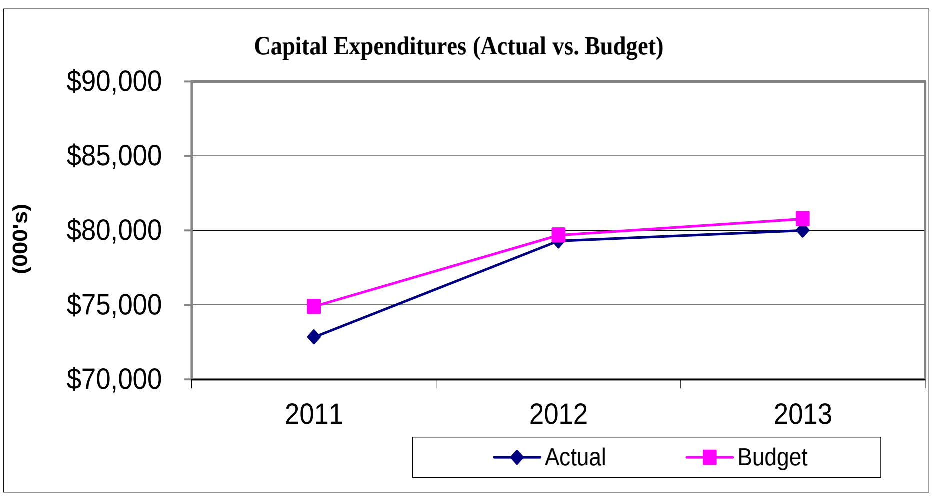
Capital Expenditures

Scope: ***Review the Company's 2013 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures (excluding capital projects carried forward from prior years) for the past three years from 2011 to 2013.

(000's)	**2011**	**2012**	**2013**
Actual	$ 72,846	$ 79,290	**$ 80,013** (1)
Budget	$ 74,894	$ 79,690	**$ 80,788**
Over (under) budget	(2.73%)	(0.50%)	**(0.96%)**

(1) Total expenditures per the 2013 Capital Budget report include the carryover amount of $4,315,000 for a total of $84,148,000. The carryover amount is made up of three projects: $2,675,000 relating to substations, $710,000 relating to general property and $750,000 relating to telecomminications. According to the Company, these expenditures will occur in 2014.



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The following table provides a summary of the capital expenditure activity in 2013 as reported in the Company's *"2013 Capital Expenditure Report"*.

	Capital Budget			**Actual Expenditures**		
(000's)	**2010-2012**	**2013**	**Total**	**2010-2012**	**2013**	**Total**
2013 Capital Projects and GEC (1) and (7)	$ -	$ 80,788	**$ 80,788**	$ -	$80,013	**$80,013**
<u>2010, 2011 and 2012 Projects carried to 2013</u>						
Rattling Brook Fisheries Compensation – 2012 (2)	5,000	-	**5,000**	2,744	213	**2,957**
Feeder Additions for Growth – 2012 (3)	1,391	-	**1,391**	1,486	59	**1,545**
Trunk Feeders – 2012 (4)	848	-	**848**	779	285	**1.064**
Company Building Renovations - 2012	935	-	**935**	620	392	**1,012**
Feeder Additions for Growth – 2011 (5)	1,281	-	**1,281**	633	1,202	**1,835**
Feeder Additions for Growth - 2010	465	-	**465**	188	198	**386**
Additions Due to Load Growth – Multi Year	1,156	-	**1,156**	1,195	-	**1,195**
Portable Substation – Multi Year (6)	879	-	**879**	192	-	**192**
	11,955	-	**11,955**	7,837	2,349	**10,186**
	$11,955	$80,788	**$92,743**	$7,837	$82,362	**$90,199**

(1) Approved by Order P.U. 31 (2012).

(2) The Company has noted that the favorable variance to budget relates to the remaining portions of a project implementation plan covering a 5 year period 2012 to 2016, directed by the Department of Fisheries and Oceans.

(3) The total budget for the 2012 Feeder Additions for Growth was $1,391,000. Total expenditures were $1,545,000 which is $154,000 above budget. The Company notes the majority of the variance is principally due to the purchase of an underground cable that was $100,000 higher than anticipated in the budget.

(4) The total budget for the 2012 Trunk Feeders project was $848,000. Total expenditures were $1,064,000 which is $216,000 above budget. The variance was caused by additional expenditures incurred to comply with municipal requirements as well as federal government requirements under the Parks Canada Environmental Protection Plan.

(5) The total budget for the 2011 Feeder Additions for Growth was $1,281,000. Total expenditures were $1,835,000 which is $554,000 above budget. The variance to budget was caused by upgrades to feeders that occurred over longer distances than originally estimated (approximately $327,000 of the variance). Additional variances were caused by property owner permissions that required revised distribution systems and routes which resulted in additional project expenditures of $150,000.

(6) The Company has noted the amounts provided in the 2012 Capital Budget Application estimated an expenditure of $879,000 in 2012 and $3,621,000 in 2013 for a total project estimate of $4,500,000. In the 2013 Capital Budget Application, the budget for 2013 was reduced to $3,121,000, lowering the total project budget estimate to $4,000,000. The order for the portable substation was placed in 2012 with delivery expected in April 2014. Actual expenditures of $192,000 and $638,000 have been incurred for the years 2012 and 2013 respectively, with a $2,600,000 carryover of expenditures to 2014 for a combined total of $3,430,000. Compared to the total project budget of $4,000,000, there is a favorable variance of $570,000. This reduction in project cost was the result of the tendered supply contract being lower than the original engineering estimate.

(7) Total expenditures per the 2013 Capital Budget include the carryover amount of $4,135,000 for a total of $84,148,000. See note 1 on the previous page.

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

(000's)	2013 Budget [1]	2013 Actuals	Variance	%
Generation - Hydro	$ 9,450	$ 7,264 [2]	$ (2,186)	(23.13%)
Generation - Thermal	284	201	(83)	(29.23%)
Substations	19,653	15,065	(4,588)	(23.35%)
Transmission	5,371	5,444 [2]	73	1.36%
Distribution	42,725	46,806 [2]	4,081	9.55%
General property	2,672	2,858	186	6.96%
Transportation	2,950	3,220	270	9.15%
Telecommunications	874	124	(750)	(85.81%)
Information systems	4,014	4,312	298	7.42%
Unforeseen	750	498	(252)	(33.60%)
General expenses capitalized	4,000	4,407	407	10.18%
Total	$ 92,743	$ 90,199	$ (2,544)	(2.74%)

1 -Includes prior years (2010 to 2012) and current year budgeted amounts as there were projects incomplete at the previous year ends. The 2013 budget for Generation - Hydro includes $5,000,000 carried forward from the 2012 budget relating to Rattling Brook Fisheries Compensation. The 2013 budget for Substations includes $879,000 carried forward from the 2012 budget relating to Portable Substation and $1,156,000 relating to Additions Due to Load Growth. The 2013 budget for Distribution includes $1,391,000, $1,281,000 and $465,000 for Feeder Additions for Growth carried forward from the budgets for the years 2012, 2011 and 2010 respectively. In addition, it includes $848,000 for Trunk Feeders carried forward from the 2012 budget. The 2013 budget for General property includes $935,000 carried forward from the 2012 budget for Company Building Renovations.

2 - 2012 actuals include the total expense for projects carried forward from the years 2010 to 2012. Total costs for Generation - Hydro includes the carry forward for Rattling Brook Fisheries Compensation costs of which $2,744,000 was spent in 2012 with a further $213,000 spent in 2013. Total costs for Substations include the carry forward for a Portable Substation costs of which $192,000 was spent in 2012 with a further $638,000 spent in 2013. Substations also include the carry forward for Additions Due to Load Growth costs of which $1,195,000 was spent in 2012 with a further $2,705,000 spent in 2013. Total costs for Distribution includes the carry forward for: 1) Feeder Additions for Growth (2012) of which $1,486,000 was spent in 2012 with a further $59,000 spent in 2013. 2) Feeder Additions for Growth (2011) of which $633,000 was spent in 2012 with a further $1,202,000 spent in 2013. 3) Feeder Additions for Growth (2010) of which $188,000 was spent in 2012 with a further $198,000 spent in 2013. Total costs for Distribution also include the carry forward for Trunk Feeders of which $779,000 was spent in 2012 with $285,000 spent in 2013. General property includes carry forwards for Company Building Renovations of which $620,000 was spent in 2012 with an additional $392,000 spent in 2013.

As indicated in the table, capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $2,544,000 (2.74%). However, for each category of expenditure, the variances ranged from an over-budget of 10.18% to an under-budget of 85.81%. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. In addition, the Company has noted that there is $4,135,000 related to projects that will be carried forward to 2013 which include Station Refurbishment and Modernization ($75,000), Company Building Renovations ($550,000), Stand-by and Emergency Power – Duffy Place ($160,000), Mobile Radio System Replacement ($750,000) and Portable Substation ($2,600,000). The explanations provided by the Company indicate that the capital expenditure variances for 2013 were caused by a number of factors. The Company has provided detailed explanations on budget to actual variances in its “2013 Capital Expenditure Report”. For a complete review of the budget variance we refer the reader to this report, Appendix A.

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

Generation - Hydro

- The favorable variance of $2,186,000 is primarily due to an extended implementation period of the *Rattling Brook Dam Replacement* project, resulting in a 2013 variance of $2,043,000, with work to be completed over a 5-year period from 2012 to 2016.

Substations

- The favorable variance of $4,588,000 is due to the carry forward to 2014 of $2,600,000 of expenditures related to *Substation Additions – Portable Substation*. In addition the purchase price of the portable substation was $570,000 lower than budget as the result of a tendered supply contract that was lower than the original engineering estimate. Favorable variances of $1,230,000 resulted from *Additions Due to Load Growth (2012-2013 Glendale Substation)* as a result of prices obtained through tendering that were lower than original engineering estimates.

Distribution

The unfavorable variance in Distribution of $4,081,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 11,376	$ 13,434	$ 2,058	18.09%
Meters	2,849	3,109	$ 260	9.13%
Services	3,705	4,280	$ 575	15.52%
Street Lighting	2,267	2,592	$ 325	14.34%
Transformers	7,983	6,710	$ (1,273)	(15.95%)
Reconstruction	3,499	4,643	$ 1,144	32.70%
Rebuild Distribution Lines	2,997	2,958	$ (39)	(1.30%)
Relocate/Place Distribution Lines for Third Parties	2,554	2,586	$ 32	1.25%
Trunk Feeders	117	154	$ 37	31.62%
2012 Feeder Additions for Growth	1,204	1,314	$ 110	9.14%
AFUDC	189	196	$ 7	3.70%
Feeder Addtions for Growth (2012)	1,391	1,545	$ 154	11.07%
Feeder Addtions for Growth (2011)	1,281	1,835	$ 554	43.25%
Feeder Addtions for Growth (2010)	465	386	$ (79)	(16.99%)
Trunk Feeders (2012)	848	1,064	216	25.47%
Total	$ 42,725	$ 46,806	$ 4,081	9.55%

- The unfavorable variance in "Extensions" of $2,058,000 is primarily due to higher than anticipated customer growth which resulted in additional new customer connections that exceeded budgets based on five year historical averages.

- The unfavorable variance in "Services" of $575,000 is primarily due to higher than anticipated customer growth which resulted in additional new customer connections that exceeded budgets based on five year historical averages.

- The unfavorable variance of $325,000 in "Street Lighting" is a result of higher than anticipated new customer connections as compared to budgeted figures.

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- The favorable variance of $1,273,000 in "Transformers" was a result of lower than anticipated contract prices.

- The unfavorable variance of $1,144,000 in "Reconstruction" is attributed to a higher than expected amount of work completed under this project. The number of high priority projects that required immediate attention was higher than the budgets based on historical 5-year average.

- The unfavorable variance of $154,000 in "2012 Feeder Additions for Growth" is due primarily to the purchase price of an underground XLPE cable which was $100,000 higher than anticipated.

- The unfavorable variance of $554,000 in "2011 Feeder Additions for Growth" is due primarily to the need to complete upgrades over a longer distance along the feeder than was anticipated in the initial project estimate ($327,000 unfavorable variance). Additional unfavorable variances of $150,000 were caused by delays in obtaining property owner permission that required a revised distribution system and an aerial feeder route which resulted in additional project expenditures.

Telecommunications

- The favorable variance of $750,000 is due to a budgeted expenditure of $750,000 for the *Mobile Radio System Replacement* project which has been carried forward to 2014.

Allowance for Unforeseen Items

- The favorable variance of $252,000 is due to unforeseen expenditures that were lower than budgeted. During 2013 the Company spent $498,000 of the $750,000 budget to correct damages to the electricity system in Central Newfoundland caused by a winter storm on November 21, 2013.

General expenses capitalized

- The unfavorable variance of $407,000 is related to an increase in the allocated portion of pension expense. Pension expenses increased as a result of the amortization of 2008 losses associated with the pension plan assets, along with a lower discount rate being used to determine the Company's accrued obligation under its defined benefit pension plan. The discount rate used for the year ended December 31, 2013 was 4.4% compared to 5.3% used for the year ended December 31, 2012.

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2013 capital expenditures are in accordance with the Capital Budget Application Guidelines Policy #1900.6 Sections A and C as noted below:

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

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

- Section C of the guidelines also notes that "should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered". This is interpreted to refer to the variance

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exceeding 10% in two consecutive years. The variance was (0.50%) in 2012 and (0.96%) in 2013 resulting in no additional reporting requirements.

Based on our review, the Company's 2013 reporting with respect to allowance for unforeseen items was not in accordance with the Capital Budget Application Guidelines Policy #1900.6 Section B as noted below:

- Under Section B, the Company used the Allowance for Unforeseen Items account to expeditiously deal with an event affecting the electrical system which could not wait for Board approval. On November 21, 2013 an unforeseen expenditure of $498,000 was required to repair damages caused by a severe winter storm in Central Newfoundland. A report entitled *November 2013 Winter Storm Central Newfoundland, March 2014* was submitted March 21, 2014. Under Section B, the final report must be submitted within 30 days of the completion of the work on the unforeseen expenditure, which in this case was December 24, 2013. The report related to the Central Newfoundland Winter Storm, submitted on March 21, 2014, was submitted over 30 days after the completion of work.

Capital Expenditure Reports

Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2013 calendar year.

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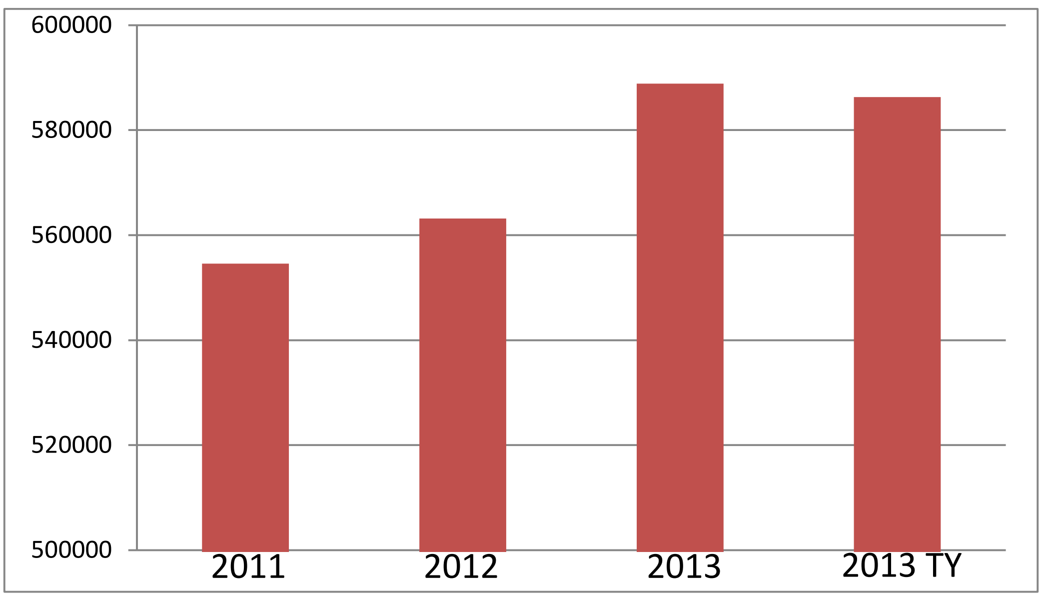
Revenue

Scope: ***Review the Company's 2013 revenue in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues for 2011 to 2013 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2011	2012	**2013**	**2013 Test Year**
Residential	$ 344,609	**$ 348,325**	**$ 367,550**	**$ 367,576**
General services				
0-10kW	12,568	**12,890**	**12,853**	**12,863**
10-100kW	67,341	**67,938**	**68,772**	**68,518**
110-1000kVA	79,954	**80,641**	**83,223**	**83,477**
Over 1000kVA	31,500	**34,664**	**36,961**	**36,112**
Street lighting	13,867	**13,968**	**14,633**	**14,525**
Forfeited discounts	2,719	**2,737**	**2,844**	**3,239**
Revenue from rates	$ 552,558	$ 561,163	**$ 586,836**	**$ 586,310**
Year over year percentage change	3.22%	1.56%	**4.57%**	**-0.09%**



The above graph demonstrates that the Company has seen a 4.57% increase in revenue from rates in 2013 as compared to 2012. The increase reflects higher electricity sales and the rebasing of customer rates effective July 1, 2013 due to the implementation of 2013/14 GRA order. There was a 1.96% increase in the overall demand in GWh for 2013. For residential sales there was an increase of 5.52% in 2013 revenue from 2012. GWh sold in this category increased by 2.59%, and the number of residential customers increased by 1.70%.

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The comparison by rate class of 2013 actual revenues to 2013 Test Year is as follows:

(000's)	Actual 2012	Actual 2013	Test Year 2013	Actual - Test Year Variance	%
Residential	$ 348,325	$ 367,550	$ 367,576	$ (26)	-0.01%
General service					
0-10kW	12,890	12,853	12,863	(10)	-0.08%
10-100kW	67,938	68,772	68,518	254	0.37%
110-1000kva	80,641	83,223	83,477	(254)	-0.30%
Over 1000kva	34,664	36,961	36,112	849	2.35%
Street lighting	13,968	14,633	14,525	108	0.74%
Forfeited discounts	2,737	2,844	3,239	(395)	-12.20%
Total revenue from rates	$ 561,163	$ 586,836	$ 586,310	$ 526	0.09%

We have also compared the 2013 test year forecast energy sales in GWh to the actual sold in 2013.

	Actual 2012	Actual 2013	Test Year 2013	Actual - Test Year Variance	%
Residential	3,441.5	3,530.6	3,532.4	(1.8)	-0.05%
General service					
0-10kW	96.4	97.5	97.8	(0.3)	-0.31%
10-100kW	673.6	680.5	685.8	(5.3)	-0.77%
110-1000kva	937.3	939.9	941.1	(1.2)	-0.13%
Over 1000kva	467.4	483.3	475.6	7.7	1.62%
Street lighting	36.0	31.5	30.9	0.6	1.94%
Total energy sales	5,652.2	5,763.3	5,763.6	(0.3)	-0.01%

Actual 2013 revenue from rates was relatively consistent with test year with an overall increase in actual sales of $526,000 (0.09%) from the 2013 Test Year. There was a 0.01% decrease in GWh sold in 2013 compared to 2013 Test Year. The largest variance in revenue can be seen in the Over 1000kva class where actual revenues increased by $849,000 (2.35%), offset by a decrease in revenues in forfeited discounts category.

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Operating and General Expenses

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

(000's)	Actual 2013	Test Year 2013	Actual 2012	Variance Actual -	Variance 2013 - 2012
Labour	$ 35,918	$ 34,955	$ 34,052	$ 963	$ 1,866
Reclass OPEB labour cost	(663)	(550)	(503)	(113)	(160)
Total Labour	35,255	34,405	33,549	850	1,706
Vehicle expense	1,881	1,860	1,827	21	54
Operating materials	1,568	1,687	1,577	(119)	(9)
Inter-company charges	1,184	1,358	1,259	(174)	(75)
Plants, Subs, System Oper & Bldgs	2,153	2,118	2,181	35	(28)
Travel	1,297	1,285	1,048	12	249
Tools and clothing allowance	1,141	1,115	1,109	26	32
Miscellaneous	1,751	1,636	1,624	115	127
Conservation	1,250	1,150	1,341	100	(91)
Taxes and assessments	1,011	1,016	988	(5)	23
Uncollectible bills	897	896	772	1	125
Insurance	1,197	1,191	1,188	6	9
Retirement allowance	84	100	114	(16)	(30)
Education, training, employee fees	392	395	285	(3)	107
Trustee and directors' fees	397	400	428	(3)	(31)
Other company fees	2,024	2,235	2,488	(211)	(464)
Stationery & copying	308	315	304	(7)	4
Equipment rental/maintenance	677	731	669	(54)	8
Communications	3,074	3,128	3,045	(54)	29
Advertising	1,113	1,485	1,029	(372)	84
Vegetation management	1,993	1,842	1,746	151	247
Computing equipment & software	799	805	828	(6)	(29)
Total other	26,191	26,748	25,850	(557)	341
Pension & early retirement program	14,744	12,189	12,896	2,555	1,848
OPEB's	10,880	10,461	9,274	419	1,606
Total employee future benefits	25,624	22,650	22,170	2,974	3,454
Total gross expenses	$ 87,070	$ 83,803	$ 81,569	$ 3,267	$ 5,501
Transfers (GEC)	(3,415)	(3,055)	(3,120)	(360)	(295)
CDM amortization	339	339	339	-	-
Deferred CDM program costs	(2,937)	(3,065)	-	128	(2,937)
Deferred seasonal rates/TOD	(71)	(140)	(84)	69	13
Deferred regulatory costs	322	417	253	(95)	69
Total net expenses	$ 81,308	$ 78,299	$ 78,957	$ 3,009	$ 2,351

The above table provides details of operating and general expenses by "breakdown" for 2012, Test Year 2013 and 2013 Actual.

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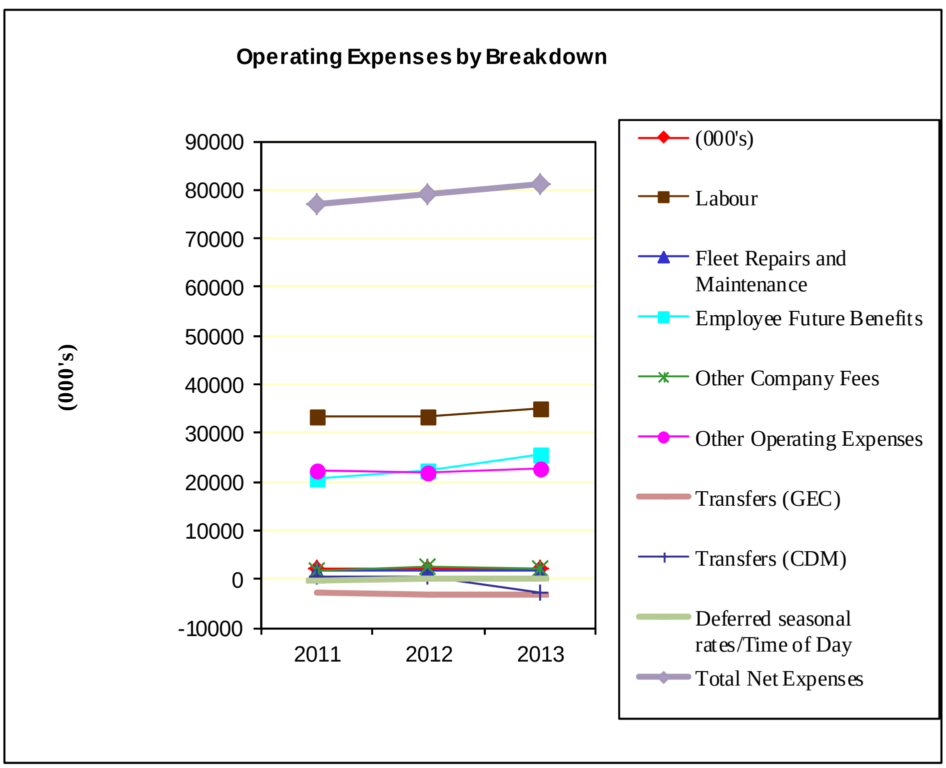
Net operating expenses in 2013 increased by $2,351,000 from 2012 and by $3,009,000 in comparison to the 2013 test year. The increase is primarily due to an increase in labour, pension costs and OPEBs. These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2013 are unreasonable.

Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2011 to 2013.

	Actual		
(000's)	**2011**	**2012**	**2013**
Labour	$ 33,351	$ 33,549	**$ 35,255**
Fleet Repairs and Maintenance	1,779	1,827	**1,881**
Employee Future Benefits	20,569	22,170	**25,624**
Other Company Fees	1,926	2,488	**2,024**
Other Operating Expenses	22,392	21,788	**22,608**
Transfers (GEC)	(2,914)	(3,120)	**(3,415)**
Transfers (CDM)	339	339	**(2,598)**
Deferred seasonal rates/Time of Day	(258)	(84)	**(71)**
Total Net Expenses	$ 77,184	$ 78,957	**$ 81,308**



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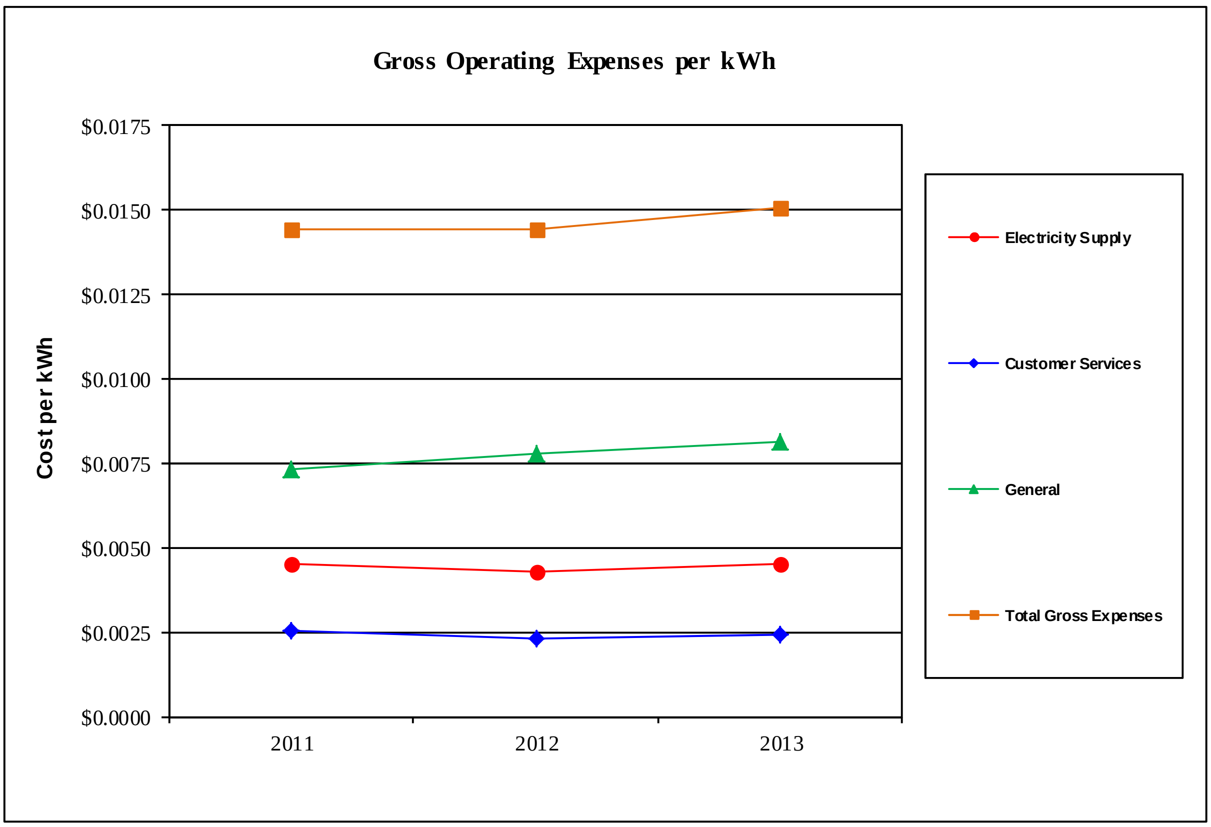
The relationship of operating expenses to the sale of energy (expressed in kWh) from 2011 to 2013 is presented in the table below.

Comparison of Gross Operating Expenses to Total kWh Sold

		Electricity Supply		Customer Services		General		Total Gross Expenses	
Year	kWh sold (000's)	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh
2011	5,552,800	$ 25,009	$0.0045	$ 14,253	$0.0026	$ 40,755	$0.0073	$ 80,017	$0.0144
2012	5,652,200	$ 24,420	$0.0043	$ 13,052	$0.0023	$ 44,097	$0.0078	$ 81,569	$0.0144
2013	5,763,300	$ 26,072	$0.0045	$ 14,009	$0.0024	$ 46,989	$0.0082	$ 87,070	$0.0151



The table and graph show that total gross expenses per kWh have increased by approximately 5% compared to 2012. This is largely due to an increase in pension costs and OPEBs included in General costs.

Our observations and findings based on our detailed review of the individual significant expense categories variances are noted below.

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Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2011 to 2013 is as follows:

	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Actual - Test Year	Actual 2013-2012
Executive Group	**6.0**	**6.0**	6.7	7.0	-	(0.7)
Corporate Office	**21.0**	**21.2**	19.2	17.9	(0.2)	1.8
Finance	**89.1**	**83.2**	72.3	71.2	5.9	16.8
Engineering and Operations	**422.1**	**430.1**	439.1	413.3	(8.0)	(17.0)
Customer Relations	**62.0**	**65.1**	60.3	62.9	(3.1)	1.7
	600.2	**605.6**	597.6	572.3	(5.4)	2.6
Temporary employees	**55.6**	**48.2**	55.0	67.8	7.4	0.6
Total	**655.8**	**653.8**	652.6	640.1	2.0	3.2
Year over year percentage change	**0.49%**	**-**	1.95%	0.08%		

The overall number of FTE's in 2013 compared to 2012 increased by 3.2. The budgeted number of FTE's in the 2013 Test Year was 653.8 versus actual of 655.8. The variances between 2013, 2013 Test Year and 2012 are the result of the following:

- The Executive decreased compared to 2012 due to timing of retirements and an employee transfer from Finance in 2012.
- The Corporate Office is higher than 2012 due primarily to the addition of a Manager of Corporate Communications and a Human Resource Advisor during 2013.
- Finance is higher than 2012 due primarily to the transfer of all stores employees from Engineering & Operations. 2013 is higher than 2013 Test Year due primarily to the transfer of regional stores employees from Engineering & Operations, whereas only the transfer of central stores employees was included in the test year.
- Engineering and Operations is lower than 2012 and 2013 Test Year due primarily to the transfer of all stores employees to Finance.
- Customer Relations is higher than 2012 due primarily to the expansion of customer energy conservation programming in 2013. 2013 is lower than 2013 Test Year due primarily to timing of the approval of the expansion of customer energy conservation programming outlined in the 2013/2014 General Rate Application as well as a shift to temporary employees for replacement coverage of temporary assignments, retirements and leaves.
- Temporary Employees are consistent with 2012 but higher than 2013 Test Year due primarily to timing of temporary assignments, retirements and leaves as well as to support Information Technology.

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An analysis of salaries and wages by type of labour and by function from 2011 to 2013, including 2013 test year is as follows:

(000's)	**Actual 2013**	**Test Year 2013**	Actual 2012	Actual 2011	**Variance Actual-Test**	**Variance 2013-2012**
Type						
Internal labour	**$ 59,784**	**$ 58,764**	$ 57,280	$ 54,158	$ 1,020	$ 2,504
Overtime	**5,228**	**4,719**	5,326	5,758	509	(98)
	65,012	**63,483**	62,606	59,916	1,529	2,406
Contractors	**13,613**	**8,668**	11,192	9,743	4,945	2,421
	$ 78,625	**$ 72,151**	$ 73,798	$ 69,659	$ 6,474	$ 4,827
Function						
Operating	**$ 35,918**	**$ 34,064**	$ 34,052	$ 33,844	$ 1,854	$ 1,866
Capital and miscellaneous	**42,707**	**38,087**	39,746	35,815	4,620	2,961
Total	**$ 78,625**	**$ 72,151**	$ 73,798	$ 69,659	$ 6,474	$ 4,827
Year over year percentage change	6.54%		5.94%	15.88%		
Actual 2013 verses Test Year 2013		8.97%				

Our review of salaries and benefits included an analysis of the year to year variances, consideration of trends in labour costs, and discussion of the significant variances with Company officials. As indicated in the above table, total labour costs for 2013 were $4,827,000 (6.54%) higher than 2012.

Internal labour costs in 2013 were higher than 2012 by 4.37% primarily due to normal salary increases.

Contractors are used to supplement the Company's work force during peak periods of construction. The 21.63% increase in contract labour from 2012 was due primarily to increased distribution and transmission work associated with the Company's 2013 capital program to address customer growth.

Also, according to the table above, the 2013 total labour costs was $6,474,000 more than the 2013 test year, representing a 8.97% increase. According to the Company, the increase in 2013 operating labour over the 2013 test year is primarily due to higher overtime costs incurred in response to loss of supply issues, peak load management, increased trouble calls and inclement weather conditions. The increase in 2013 capital and miscellaneous labour over the 2013 test year is primarily due to increase distribution work resulting from higher customer growth than anticipated.

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As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and short term incentive). The results of our analysis for 2011 to 2013, including 2013 test year are included in the table below:

(000's)	Salary Cost Per FTE Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual-Test	Variance 2013-2012
Total reported internal labour costs	**$ 59,784**	**$ 59,655**	$ 57,280	$ 54,158	$ 129	$ 2,504
Benefit costs (net)	**(7,502)**	**(7,766)**	(7,074)	(6,909)	264	(428)
Other adjustments	**(506)**	**(508)**	(525)	(376)[1]	2	19
Base salary costs	**51,776**	**51,381**	49,681	46,873	395	2,095
Less: executive compensation	**(1,893)**	**(1,684)**	(1,806)	(1,690)	(209)	(87)
Base salary costs (excluding executive)	**$ 49,883**	**$ 49,697**	$ 47,875	$ 45,183	$ 186	$ 2,008
FTE's (including executive members)	**655.8**	**653.8**	652.6	640.1		
FTE's (excluding executive members)	**651.8**	**649.8**	648.6	636.1		
Average salary per FTE	**78,951**	**78,588**	76,128	73,228		
% increase	**3.71%**		3.96%	4.41%		
% increase "Actual 2013" vs Test Year	**0.46%**					
Average salary per FTE (excluding executive members)	**76,531**	**76,480**	73,813	71,031		
% increase	**3.68%**		3.92%	4.25%		
% increase "Actual 2013" vs Test Year	**0.07%**					

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

The above analysis indicates that for 2013 the rate of increase in average salary per FTE has been fairly consistent from 2011 to 2013.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2011 to 2013 and the targets set for 2013:

Measure	Target 2013	Actual 2013	Actual 2012	Actual 2011
Controllable Operating Costs/Customer	**$220.2**	$217.6	$222.2	$214.2
Earnings	**35.3m**	36.5m	34.2m	33.7m
Reliability - Duration of Outages (SAIDI)	**2.53**	2.23	2.44	2.57
Customer Satisfaction - % Satisfied	**87.6%**	85.9%	86.7%	88.5%
Customer Satisfaction - 1st Call Resolution	**-**	-	88.7%	88.5%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	**1.05**	0.52	1.74	1.8
Regulatory Performance	**Subjective**	150%	-	-

The 2013 STI results were adjusted to remove the impact of severe weather conditions and energy supply issues in January and November. Also in 2013, First Call Resolution was replaced with Regulatory Performance. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or cost based analyses. For 2013, the key determinants of the result of 150% were the efficient management of (i) the 2013/2014 general rate application, including the public hearing process,

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(ii) the 2014 capital budget application, (iii) the $14.5 million Bell Island Cable Replacement supplemental capital application, and (iv) the multiple Newfoundland & Labrador Hydro applications filed in 2013.

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

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

Classification	Corporate Performance	Individual Performance
President and CEO	70%	30%
Other Executives	50%	50%
Managers	50%	50%

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

The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. The STI pay for 2013 is established as a percentage of base pay for the three employee groups. For 2013, measures relating to 'controllable operating costs/customer', 'earnings', 'SAIDI', 'safety' and 'regulatory performance' metrics were met, however the 'customer satisfaction - % satisfied' metric fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2011 to 2013:

STI Payout

	Target 2013	Actual 2013	Target 2012	Actual 2012	Target 2011	Actual 2011
President	50%	70.0%	50%	70.0%	50%	63.6%
Executive	35-40%	52.1%	35-40%	51.1%	35-40%	48.2%
Managers	15%	21.2%	15%	20.2%	15%	16.9%

STI actual payout rates for 'executive' and 'manager' employee groups are higher than in the prior year, while they have remained the same for the President.

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In dollar terms, the STI payouts for 2011 to 2013 are as follows:

	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
President	**$ 294,000**	$ 280,000	$ 245,000	$ 14,000
Executive	**404,000**	381,000	345,000	23,000
Managers	**302,000**	271,000	245,200	31,000
Total	**$1,000,000**	$ 932,000	$ 835,200	$ 68,000
Year over year percentage change	**7.30%**	11.59%	18.17%	

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In 2013, the non-regulated portion (before tax adjustment) was $285,225 (2012 - $170,200).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2011 to 2013.

	Base Salary	Short Term Incentive	Other	Total
2013				
Total executive group	$ 1,195,019	$ 698,000	$ 126,744	$ 2,019,763
Average per executive (4)	**$ 298,755**	**$ 174,500**	**$ 31,686**	**$ 504,941**
2012				
Total executive group	$ 1,145,021	$ 661,000	$ 129,201	$ 1,935,222
Average per executive (4)	**$ 286,255**	**$ 165,250**	**$ 32,300**	**$ 483,806**
2011				
Total executive group	$ 1,100,319	$ 590,000	$ 127,325	$ 1,817,644
Average per executive (4)	**$ 275,080**	**$ 147,500**	**$ 31,831**	**$ 454,411**
% Average increase 2013 vs 2012	**4.37%**	**5.60%**	**(1.90%)**	

Base salary for the executive group increased from 2012 due to salary increases approved by the Board of Directors. Base salaries have been agreed to the 2013 Board of Directors' minutes, and STI payouts have been agreed to the 2014 Board of Directors' minutes.

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Company Pension Plan

For 2013, we reviewed the accounts supporting the gross charge of $14,744,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2011 to 2013, including the 2013 test year is as follows:

	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual-Test	Variance 2013-2012
Pension expense per actuary	$ 12,744,000	$ 10,405,000	$ 11,153,000	$ 10,056,965	$ 2,339,000	$ 1,591,000
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	560,000	496,000	484,934	444,163	64,000	75,066
Group RRSP @ 1.5%	440,000	494,000	459,000	467,000	(54,000)	(19,000)
Individual RRSP's	1,013,000	844,000	813,000	616,000	169,000	200,000
Less: Refunds (net of other expenses)	(13,000)	(50,000)	(14,000)	(18,128)	37,000	1,000
Total	$ 14,744,000	$ 12,189,000	$ 12,895,934	$ 11,566,000	$ 2,555,000	$ 1,848,066
Year over year percentage change	14.33%		11.50%	52.42%		
% increase Actual 2013 vs Test Year		20.96%				

Overall, pension expense for 2013 is higher than 2012 primarily due to a lower discount rate at December 31, 2012 (4.40% compared to 5.00%), which is used to determine the pension obligation for 2013, as well as a lower service life of active members. The pension expense for 2013 is higher than test year 2013 primarily due to an increase in amortization from an actuarial loss of $38.4 million booked at 2012 year-end. The loss was largely due to a decrease in interest rate from the initial projection of 4.90% to the year-end 2012 actual rate of 4.40%.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses increased by 15.48% in 2013.

The employer's portion of the contributions to the Group RRSP is calculated as 1.5% of the base salary paid to the plan participants. The increase of approximately $181,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2012 was primarily the result of wage increases and new hires in the year. This was partially offset by retirements and terminations.

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Retirement Allowance

The retirement allowance costs incurred by the Company over the period from 2011 to 2013, including 2013 test year are as follows:

(000's)	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual-Test	Variance 2013-2012
Terminations and Severance	$ 68	$ 90	$ 100	$ 154	$ (22)	$ (32)
Other Retiring Allowance Costs	16	10	14	10	6	2
Total	$ 84	$ 100	$ 114	$ 164	$ (16)	$ (30)
Year over year percentage change	-26.32%		-30.49%	-76.97%		

There were 26 retirements in 2013, compared to 27 retirements in 2012.

Other Post-Employment Benefits ("OPEBs")

In its 2010 General Rate Application, the Company proposed the implementation of the accrual method of accounting for OPEBs expenses. The proposal included a deferral mechanism to capture annual variances arising from changes in the discount rate and other assumptions, and recommendations related to the recovery of the transitional balance associated with the adoption of accrual accounting for OPEBs costs. In P.U. 31 (2010) the Board decided the Company should use the accrual method of accounting for OPEBs costs and income tax related to OPEBs as of January 1, 2011.

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

The components of OPEBs expense for 2011 to 2013, including the 2013 test year is as follows:

(000s)	2013 Actual	2013 Test Year	2012 Actual	2011 Actual
Accrued OPEBs	$ 7,957	$ 7,419	$ 6,212	$ 5,895
Amortization of transitional balance	3,504	3,504	3,504	3,504
Amount capitalized	(581)	(462)	(442)	(396)
	$ 10,880	$ 10,461	$ 9,274	$ 9,003

Consistent with the explanation provided above for pension costs, OPEB costs were higher in 2013 due to a lower discount rate at December 31, 2012, which is used to determine the Company's OPEBs obligation.

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Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003), P.U. 32 (2007) and P.U. 43 (2009);
- compared intercompany charges for the years 2011 to 2013 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2013 and investigated any unusual items;
- vouched a sample of transactions for 2013 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and,
- reviewed the methodology developed by Fortis Inc. in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2011 to 2013 for charges to and from Newfoundland Power Inc.:

	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges from related companies				
Regulated	**$ 203,300**	$ 202,524	$ 130,719	$ 776
Non-Regulated	**1,467,175**	1,575,092	1,602,265	(107,917)
Total	**$ 1,670,475**	$ 1,777,616	$ 1,732,984	$ (107,141)
Charges to related companies	**$ 506,639**	$ 659,162	$ 913,593	$ (152,523)

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

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

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We reviewed Fortis Inc.'s methodology to estimate its recoverable expenses over the first three quarters as well as its "true up" calculation for the 4th quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no changes to the methodology in 2013.

- Fortis Inc. estimated its net pool of operating expenses for 2013 in Q4 2012 as part of its annual business planning process and determined its estimated billings based on the pro-rata portion of such net costs using the estimated assets of subsidiaries. For Quarters 1 through 3 Fortis Inc. billed evenly based upon 25% of the estimated annual amount.
- Fortis Inc. used actual year-to-date expenditures up to October and estimated November and December's expenses for the determination of its actual "true up" calculation. Fortis also used actual assets at September 30, 2013 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of November and December's expenditures had a minimal impact.

During the fourth quarter of 2013, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $1,184,000 and are summarized as follows:

2013 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$558,000	Non-regulated
Director Fees	136,000	Non-regulated
Consulting and Legal fees	112,000	Non-regulated
Trustee Agent Fees	53,000	Regulated
Audit and Other Fees	39,000	Non-regulated
Public Reporting Costs	51,000	Non-regulated
Annual Meeting Expenses	41,000	Non-regulated
Travel (Board and Other)	49,000	Non-regulated
Insurance (D&O)	42,000	Non-regulated
Other Costs	103,000	Non-regulated
	1,184,000	
Less amounts previously billed:		
Q1 2013	310,000	
Q2 2013	310,000	
Q3 2013	306,000	
Q4 2013 balance owing	$ 258,000	

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For 2013, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 8.85%, down from 9.72% in 2012.

As detailed above, trustee agent fees for $53,000 were the only expenses allocated to regulated operations by the Company relating to recoverable expenses. Certain other direct costs were recovered by Fortis Inc. by separate invoicing throughout the year and are detailed in the analysis below of regulated and non-regulated operations.

The analysis below is a review of the intercompany variances related to charges to and from Fortis Inc. as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2011 to 2013 with Fortis Inc.:

Intercompany Transactions

(Regulated)	**Actual 2013**	**Actual 2012**	**Actual 2011**	**Variance 2013-2012**
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 53,000**	$ 52,000	$ 51,000	$ 1,000
Miscellaneous	**14,185**	13,362	7,629	823
Non-Joint Use Poles	**-**	-	11,566	-
	$ 67,185	$ 65,362	$ 70,195	$ 1,823
Year over year percentage change	**2.79%**	-6.89%	-1.13%	
Charges to Fortis Inc.				
Postage and couriers	**$ 24,565**	$ 24,457	$ 22,263	$ 108
Staff charges	**97,979**	201,332	299,786	(103,353)
Staff charges - insurance	**183,267**	203,524	179,005	(20,257)
IS Charges	**309**	-	-	309
Pole removal and installation	**572**	3,606	20,191	(3,034)
Miscellaneous	**6,090**	13,367	92,974	(7,277)
	$ 312,782	$ 446,286	$ 614,219	$ (133,504)
Year over year percentage change	**-29.91%**	-27.34%	-19.99%	

The most significant fluctuation from our analysis of regulated intercompany charges is a $103,353 decrease in staff charges charged to Fortis Inc. Charges in 2012 related to Newfoundland Power staff involvement in the acquisition of Central Hudson Gas & Electric by Fortis Inc. With the successful closure of this acquisition in early 2013, the involvement by Newfoundland Power staff was significantly reduced from the previous year.

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The following table provides a summary and comparison of the non-regulated intercompany transactions for 2011 to 2013:

(Non-Regulated)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges from Fortis Inc.				
Director's fees and travel	**$ 185,000**	$ 219,000	$ 200,000	$ (34,000)
Annual and quarterly reports	**90,000**	96,000	117,000	(6,000)
Staff charges	**558,000**	557,000	574,000	1,000
Miscellaneous	**634,175**	697,130	711,265	(62,955)
	$ 1,467,175	$ 1,569,130	$ 1,602,265	$ (101,955)
Year over year percentage change	**(6.50%)**	(2.07%)	14.29%	

The total non-regulated charges from Fortis Inc. have decreased by 6.50% ($101,955) from 2012.

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The following table provides a summary and comparison of the other intercompany transactions for 2011 to 2013:

Intercompany Transactions (Other)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges to Fortis Properties				
Staff charges	**$ -**	$ 864	**$ -**	$ (864)
Staff charges - insurance	**30,894**	33,089	37,042	(2,195)
Stationary costs	**352**	529	678	(177)
Miscellaneous	**2,770**	3,134	2,147	(364)
	$ 34,016	$ 37,616	$ 39,867	$ (3,600)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 52,961**	$ 58,212	$ 37,387	$ (5,251)
Miscellaneous	**1,636**	8,944	8,029	(7,308)
	$ 54,597	$ 67,156	$ 45,416	$ (12,559)
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 4,091**	$ 3,697	$ 1,622	$ 394
Staff charges	**16,587**	10,658	7,065	5,929
IS charges	**4,080**	6,224	3,351	(2,144)
Miscellaneous	**370**	350	360	20
	$ 25,128	$ 20,929	$ 12,398	$ 4,199
Charges to Maritime Electric				
Staff charges	**$ 6,976**	$ 6,418	$ 16,296	$ 558
Staff charges - insurance	**1,954**	10,005	2,693	(8,051)
IS charges	**2,856**	1,915	4,787	941
Miscellaneous	**573**	540	550	33
	$ 12,359	$ 18,878	$ 24,326	$ (6,519)
Charges from Maritime Electric				
Staff charges	**$ -**	$ 33,932	$ -	$ (33,932)
Miscellaneous	**5,614**	5,999	9,211	$ (385)
	$ 5,614	$ 39,931	$ 9,211	$ (34,317)
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 4,647**	$ -	$ -	$ 4,647
Charges to Central Hudson Gas & Electric				
Staff charges - insurance	**$ 6,702**	$ -	$ -	$ 6,702
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	**$ 6,177**	$ -	$ 432	$ 6,177
	$ 6,177	$ -	$ 432	$ 6,177
Charges to Fortis US Energy Corp				
Staff charges - insurance	**$ 74**	$ 1,176	$ 2,581	$ (1,102)

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Intercompany Transactions (Other) Cont'd.	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges to Belize Electricity				
Staff charges	$ -	$ -	$ -	$ -
Staff charges - insurance		-	1,296	-
Miscellaneous	-	-	1,176	-
	$ -	$ -	$ 2,472	$ -
Charges to Fortis Alberta Inc.				
Staff charges	$ -	$ -	$ 18,219	$ -
Staff charges - insurance	3,359	341	3,365	3,018
Miscellaneous	3,650	3,270	3,120	380
	$ 7,009	$ 3,611	$ 24,704	$ 3,398
Charges from Fortis Alberta Inc.				
Staff charges	$ -	$ -	$ 4,805	$ -
Miscellaneous	41,411	30,637	-	10,774
	$ 41,411	$ 30,637	$ 4,805	$ 10,774
Charges to Fortis BC Inc.				
Staff charges	$ -	$ 16,023	$ -	$ (16,023)
IS charges	11,424	13,405	13,405	(1,981)
Staff charges - insurance	2,768	715	5,869	2,053
Miscellaneous	2,363	2,330	1,944	33
	$ 16,555	$ 32,473	$ 21,218	$ (15,918)
Charges from Fortis BC Inc.				
Miscellaneous	$ 8,740	$ -	$ 1,092	$ 8,740
Charges to Fortis BC Holdings				
Staff charges	$ -	$ -	$ 10,215	$ -
Staff charges - insurance	2,882	324	2,983	2,558
Miscellaneous	6,290	6,500	6,547	(210)
	$ 9,172	$ 6,824	$ 19,745	$ 2,348
Charges to Caribbean Utilities Co. Limited				
Staff charges	$ 54,492	$ 67,524	$ 6,938	$ (13,032)
Staff charges - insurance	11,048	162	21,168	10,886
Miscellaneous	1,400	281	-	1,119
	$ 66,940	$ 67,967	$ 28,106	$ (1,027)
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	$ 21,106	$ 5,400	$ -	$ 15,706

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Intercompany Transactions (Other) Cont'd.	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charges to Fortis Turks and Caicos				
Staff Charges	$ -	$ 6,638	$ 117,504	$ (6,638)
Staff Charges - insurnce	9,477	16,764	5,946	(7,287)
Miscellaneous	248	-	75	248
	$ 9,725	$ 23,402	$ 123,525	$ (13,677)

The most significant fluctuations from our analysis of other intercompany charges for 2013 compared to 2012 are as follows:

- Staff charges from Maritime Electric decreased by $33,932 from 2012. The 2012 charges related to Maritime Electric staff working on restoration of power in the aftermath of Tropical Storm Leslie.
- Staff charges to FortisBC Inc. decreased by $16,023 from 2012. The 2012 charges related to engineering services provided for a proposed hydroelectric generating project being considered by a subsidiary of FortisBC Inc.

On three occasions during the year the Company entered into short term loan agreements with related parties. These loans are as follows:

Lender	Amount Borrowed	Date Borrowed	Date Repaid	Interest Rate	Total Interest Cost
Maritime Electric Ltd	$ 15,000,000	April 22, 2013	June 27, 2013	1.57%	$ 42,584
Maritime Electric Ltd	$ 10,000,000	July 22, 2013	Sept 20, 2013	1.60%	$ 26,301
Maritime Electric Ltd	$ 8,000,000	Sept 20, 2013	Nov 7, 2013	1.56%	$ 16,412
	$ 33,000,000				$ 85,297

In Order P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2013. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2013.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2013/14 General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2013 and noted some exceptions. Only staff charges relating to the Director of Risk Management are charged at $108 per hour, whereas staff charges relating to routine insurance matters (e.g.; coverage queries, damage claims, arranging for insurance certificates) are based on the recovery of fully distributed costs (hourly rate plus 71% markup). These charges were further investigated to determine the impact of using a lower rate. It was determined that had the Company charged $108 per hour rather than the fully distributed cost, an additional $17,500 in staff insurance charges to related parties would result. The Company indicated that this is in accordance with Section 6.5 – Shared Corporate Services of the Newfoundland Power Inc. Inter-Affiliate Code of Conduct (May 2011) submitted to the Board on June 10, 2011.

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

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Other Company Fees and Deferred Regulatory Costs

The procedures performed for this category included a review of the transactions for 2013 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Other company fees				
Other company fees	$ 1,648	$ 1,389	$ 1,748	$ 259
Regulatory hearing costs - other	376	1,099	178	(723)
	$ 2,024	$ 2,488	$ 1,926	$ (464)
Year over year percentage change	-18.6%	29.2%	13.8%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 322	$ 253	$ 253	$ 69
Year over year percentage change	27.3%	0.0%	-44.2%	

Total company fee costs for 2013 were lower than 2012 actual by $464,000 primarily due to reduced consultants work required for regulatory activity partially offset by increases in consultant costs required for expansion of customer energy conservation programming. Deferred regulatory costs are discussed in the section of the report relating to regulatory assets and liabilities.

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

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Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2011 to 2013 is as follows:

(000's)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Miscellaneous	**$ 1,048**	$ 857	$ 858	$ 191
Cafeteria and lunchroom supplies	**95**	93	97	2
Promotional items	**119**	101	118	18
Computer software	**5**	34	3	(29)
Damage claims	**241**	215	141	26
Community relations activities	**11**	3	3	8
Donations and charitable advertising	**172**	221	180	(49)
Books, magazines and subscriptions	**33**	67	45	(34)
Misc. lease payments	**27**	33	23	(6)
Total miscellaneous expenses	**$ 1,751**	$ 1,624	$ 1,468	$ 127
Year over year percentage change	**7.83%**	10.63%	(13.80%)	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2012 to 2013 these expenses have increased by 7.83% overall, primarily due to the expansion of customer energy conservation programming.

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

Our procedures in this expense category for 2013 included vouching a sample of transactions within the "miscellaneous category" to supporting documentation. Based upon the results of our procedures nothing has come to our attention to indicate that the 2013 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2013 Conservation and Demand Management Report with the Board. This report provided a summary of 2013 CDM activities and costs as well as the outlook for 2013.

In 2013, the Company offered four residential customer energy conservation programs. Those customer energy conservation programs for (i) Energy Star windows, (ii) insulation, (iii) high performance thermostats, and (iv) heat recovery ventilators ("HRV's") are bundled together for marketing purposes as the takeCharge Energy Savers. The primary objective of these programs are to reduce space heating energy consumption and provide reductions in peak demand.

Costs in 2013 totaled $3,929,000 compared to $3,397,000 in 2012, a $532,000 increase over 2012. The increase that was experienced in 2013 is primarily due to spending in the Conservation Program category – specifically in the Energy Saver program (Windows). This category experienced a $409,000 increase over 2012 costs. In 2013, $2,937,000 ($2,085,000 after tax) in CDM costs were deferred with annual amortization in the amount of $298,000 to commence in 2014.

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Going forward, the Company plans to increase program participation among customers retrofitting existing homes, launch a new residential conservation program, and conduct research to enhance its planning activities.

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

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Other Operating and General Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating and general expenses by breakdown were also analyzed for any unusual variances between 2013 and 2012, including test year 2013, as follows:

(000's)	Actual 2013	Test Year 2013	Actual 2012	Actual 2011	Variance Actual - Test	Variance 2013-2012
Vehicle expense	**1,881**	**1,860**	**1,827**	1,779	21	54
Operating materials	**1,568**	**1,687**	**1,577**	1,533	(119)	(9)
Plants, Subs, System Oper & Bldgs	**2,153**	**2,118**	**2,181**	1,993	35	(28)
Travel	**1,297**	**1,285**	**1,048**	1,282	12	249
Tools and clothing allowance	**1,141**	**1,115**	**1,109**	1,031	26	32
Conservation	**1,250**	**1,150**	**1,341**	2,184	100	(91)
Taxes and assessments	**1,011**	**1,016**	**988**	895	(5)	23
Uncollectible bills	**897**	**896**	**772**	1,204	1	125
Insurance	**1,197**	**1,191**	**1,188**	1,082	6	9
Education, training, employee fees	**392**	**395**	**285**	318	(3)	107
Trustee and directors' fees	**397**	**400**	**428**	399	(3)	(31)
Stationery & copying	**308**	**315**	**304**	302	(7)	4
Equipment rental/maintenance	**677**	**731**	**669**	629	(54)	8
Communications	**3,074**	**3,128**	**3,045**	3,086	(54)	29
Advertising	**1,113**	**1,485**	**1,029**	906	(372)	84
Vegetation management	**1,993**	**1,842**	**1,746**	1,612	151	247
Computing equipment & software	**799**	**805**	**828**	774	(6)	(29)
Transfers (GEC)	**(3,415)**	**(3,055)**	**(3,120)**	(2,914)	(360)	(295)
Transfers (CDM)	**339**	**339**	**339**	339	-	-
Deferred seasonal rates/Time of Day	**(71)**	**(140)**	**(84)**	(258)	69	13

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

- Operating materials were lower than test year primarily due to less operating materials being required for distribution and substation maintenance work encountered.
- Travel costs increased by $249,000 due to higher employee relocation costs.
- Uncollectible bills increased by $125,000 primarily due to 2012 including a reversal of a provision for potentially uncollectible amounts related to the Bell Aliant joint-use pole sale. In addition, uncollectible bills vary from year to year as a result of general economic conditions.
- Conservation was higher than test year primarily due to higher customer participation in energy conservation rebate programs leading to increased incentives.
- Education, training and employee fees increased by $107,000 primarily due to increased training requirements for customer service and mobile technology.
- Advertising costs is lower than test year by $372,000 primarily due to timing of the approval of the expansion of customer energy programming outlined in the 2013/14 General Rate Application.
- Vegetation management costs increased over 2012 and test year primarily due to increased vegetation management activity for distribution and plant operations.
- GEC transfers increased over 2012 and test year primarily due to higher pension costs.

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Other Costs

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

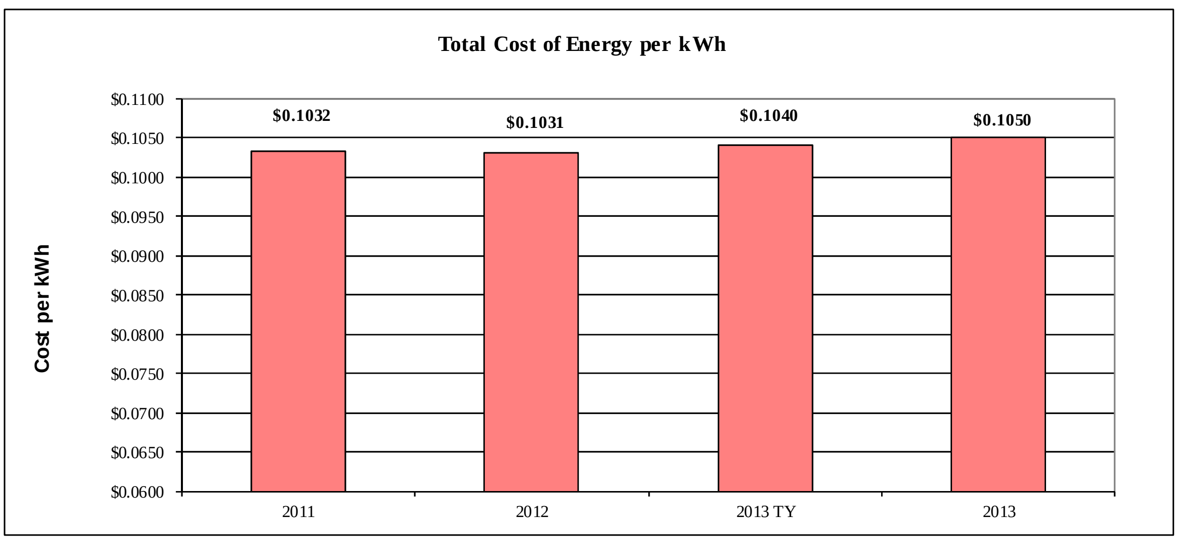
The following table and graph provide the total cost of energy (expressed in kWh) from 2011 to 2013, including 2013 test year (includes non-regulated):

(000's)

Year	kWh sold	Operating Expenses	Purchased Power	Deferred Cost recoveries and amortizations	Depreciation	Finance Charges*	Income Taxes	Net Earnings	Total Cost of Energy	Cost per kWh
2011	5,552,800	$ 77,184	$ 369,484	$ (2,363)	$ 42,695	$ 35,944	$ 17,661 [1]	$ 32,467 [1]	$ 573,072	$ 0.1032
2012	5,652,200	$ 78,957	$ 380,374	$ (4,850)	$ 47,372 [2]	$ 35,856	$ 8,007 [2]	$ 37,204	$ 582,920	$ 0.1031
2013 TY	5,763,600	$ 78,299	$ 389,103	$ (768)	$ 46,647	$ 35,487	$ 14,702	$ 35,906	$ 599,376	$ 0.1040
2013	5,763,300	$ 81,308	$ 390,210	$ (768)	$ 51,300	$ 36,034	$ (2,877)	$ 49,920	$ 605,127	$ 0.1050

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

2 - There was a reclass related to income tax and depreciation in 2012 of $2,854,000



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Purchased Power

We have reviewed the Company's purchased power expense for 2013 and have investigated the reasons for any fluctuations and changes. We performed a recalculation of the purchased power to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Purchased power expense increased by $9.8 million, from $380.4 million in 2012 to $390.2 million in 2013. According to the Company, the increase resulted from (i) electricity sales growth; (ii) lower generation than water inflows at the Company's hydroelectric generating facilities; and, (iii) the amortization of the 2011 balance of the Weather Normalization Account.

Purchased power expense for 2013 test year is $389.1 million compared to $390.2 million in 2013, which represents an increase of $1.1 million or a 0.3% increase.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the Gannett Fleming Depreciation Study based on plant in service as of December 31, 2010 and assessed the reasonableness of depreciation expense.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. The study for plant in service as of December 31, 2010 was completed in 2011. The study was included in the 2013-2014 General Rate Application by the Company and was approved in P.U. 13 (2013), including the approval of the accumulated depreciation reserve variance of $2.6 million to be amortized over the average remaining service life of the related assets. The new depreciation rates from the 2010 depreciation study, including the amortization of the accumulated depreciation reserve, were implemented effective January 1, 2013.

Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method in its 2010 depreciation study as this method provides for a better match of depreciation expense and loss in service. The next study for plant in service is to be completed as of December 31, 2014 and included in the 2015-2016 General Rate Application.

The objective of our procedures in this section was to ensure that the 2013 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2010 Depreciation Study undertaken by Gannett Fleming, Inc.

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

- agreed all depreciation rates to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2013; and,
- assessed the overall reasonableness of the depreciation for 2013.

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Amortization expense for 2013 is $51,300,000 as compared to $47,372,000 for 2012, representing an 8.29% increase. The 2013 and 2012 depreciation expense excludes the impact of the income tax deduction resulting from the cost of the removal of property, plant and equipment. The following table reconciles the depreciation as reported in the financial statements and the depreciation of fixed assets:

('000s)	2013	2012	Variance 2013-2012	%
Depreciation and amortization as reported	$ 51,300	$ 47,372	$ 3,928	8.29%
Less: Tax on Cost of Removal [1]	(4,336)	(2,854)	(1,482)	51.93%
Depreciation of Fixed Assets	$ 46,964	$ 44,518	$ 2,446	5.49%

Note 1: Recognised as income tax for financial reporting purposes.

The change to 2012 depreciation was a change in presentation only and had no impact on net earnings.

The following table provides a comparison of the depreciation of fixed assets for 2013, 2013 test year and 2012:

('000s)	2013	2013 TY	2012	Variance 2013-2013TY	Variance 2013-2012
Depreciation of Fixed Assets	$ 46,964	$ 46,647	$ 44,518	$ 317	$ 2,446

Depreciation of fixed assets for 2013 is $46,964,000 as compared to $44,518,000 for 2012, representing a 5.49% increase. The change is attributable to the implementation of new rates approved in P.U. 13 (2013) and an increase of depreciable assets by approximately $61,907,000. The variance of depreciation of fixed assets for 2013 as compared to 2013 test year was $317,000, representing a 0.7% increase.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006), P.U. 32 (2007) and P.U. 13 (2013), as well as the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2010 have been incorporated into the Company's depreciation calculations for 2013.

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Interest and Finance Charges

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

The following table summarizes the various components of finance charges expense:

(000's)	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Interest				
Long-term debt	**$ 35,123**	$ 35,039	$ 35,444	$ 84
Other	**1,092**	921	702	171
Amortization				
Debt discount	**302**	337	308	(35)
Interest charged to construction	**(483)**	(441)	(510)	(42)
Total finance charges	**$ 36,034**	$ 35,856	$ 35,944	$ 178
Year over year percentage change	**0.50%**	-0.24%	-0.26%	

In the above table, the increase in interest on long term debt compared to 2012 is attributable to the increasing amount of bonds outstanding associated with the $70 million first mortgage sinking bond issue in 2013. The increase in other interest is due to higher borrowings under the Company's credit facility during the year. The test year 2013 interest and finance charges was $35,931,000 for financial reporting purposes (or $35,487,000 including the equity component of interest charged to construction). The variance of interest and finance charges for 2013 as compared to 2013 test year for financial reporting purposes was $103,000, representing a 0.03% increase.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2013 are unreasonable.

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Income Tax Expense

We have reviewed the Company's income tax expense for 2013 and have noted that the effective income tax rate decreased from 17.7% in 2012 to -6.1% in 2013. This decrease is primarily due to the allocation of the Part VI.1 tax liability and related Part 1 tax deduction from Fortis to the Company in 2013. Excluding the impact of the Part V1.1 tax for 2013, 20113 test year and 2012 results in the following effective rates:

('000s)	Actual 2013	Test Year 2013	Actual 2012	Variance 2013-2013 TY	Variance 2013-2012
Income tax expense *	$ (2,877)	$ 14,702	$ 8,007	$ (17,579)	$ (10,884)
Add back: Part VI.1 tax	12,814	-	2,589	12,814	10,225
	$ 9,937	$ 14,702	$ 10,596	$ (4,765)	$ (659)
Earnings before income taxes	$ 47,043	$ 50,608	$ 45,211	(3,565)	1,832
Effective income tax rate excluding Part V1.tax	21.1%	29.1%	23.4%	-7.9%	-2.3%

* The 2012 income tax expense was reclassifed in 2013 by $2,854,000 for the impact of the income tax deduction associated with the cost of removal of the Company's property, plant and equipment.

With the exclusion of the Part VI.1 tax, the effective rate decreased by 2.3% in 2013 compared to 2012 and decreased by 7.9% in 2013 compared to 2013 test year. The decrease for both 2013 actual to 2012 actual and 2013 actual to 2013 test year is primarily resulting from increased depreciation expense associated with the future cost of removal of the Company's property, plant and equipment recorded in depreciation expense. There was no change in the statutory tax rate for 2012, 2013 test year and 2013 which remained at 29%.

Upon adoption of U.S. GAAP in 2012, the Company was required to recognize the impact of the difference between enacted tax rates and substantially enacted tax rates related to the allocation of the unregulated Part VI.1 tax deduction from Fortis to Newfoundland Power. This resulted in the Company recording a $12.8 million income tax recovery.

Based upon our review of the Company's calculations, and considering the impact of timing differences, nothing has come to our attention to indicate that income tax expense for 2013 is unreasonable.

Costs Associated with Curtailable Rates

In P.U. 7 (1996-97), the Board ordered that beginning January 1, 1997, all costs associated with curtailable rates shall be charged to regulated expenses, and not to the Rate Stabilization Account. The Board ordered that the demand credit for curtailment continue at $29/kVA until April 30, 1998. In P.U. 30 (1998-99), the Board ordered that this rate be extended until a review of the curtailment service option is presented at a public hearing. In P.U. 19 (2003) the Board accepted the recommendations of the parties, as set out in the Mediation Report, that the use of the Curtailable Service Option Credit of $29/kVA be retained as is until a change in Hydro's wholesale rates causes the matter to be reconsidered.

Twenty–one customers participated in the Option during the 2012-2013 winter season. The total of the curtailment credits for 2013 was $222,074 compared to the 2012 credits of $332,754. Total operating costs incurred by the Company in 2013 were $243,392 compared to $357,152. The curtailment credit total for the 2012-2013 winter season is lower than the previous season's total primarily due to a higher number of curtailment failures this past winter season. There were 17 curtailment failures during this winter season. This

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is up significantly from last year. More than half of the curtailment failures resulted from customer's standby generation being unavailable when requested.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and P.U. 30 (1998-99).

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Non-Regulated Expenses

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

* assessed the Company's compliance with Board Orders;
* compared non-regulated expenses for 2013 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2013 and investigated any unusual items;
* assessed the reasonableness and appropriateness of the amounts being charged.

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

	Actual 2013	Actual 2012	Actual 2011	Variance 2013-2012
Charged from Fortis Companies:				
Annual report	**$ 90,000**	$ 96,000	$ 117,000	$ (6,000)
Directors' fees and travel	**185,000**	219,000	200,000	(34,000)
Hotel/Banquet Facilities	**-**	5,700	-	(5,700)
Staff charges	**558,000**	557,000	574,000	1,000
Miscellaneous	**634,200**	697,400	711,300	(63,200)
	1,467,200	1,575,100	1,602,300	(107,900)
Performance Share Unit Plan 1	**65,000**	-	-	65,000
Donations and charitable advertising	**221,200**	286,800	266,300	(65,600)
Executive short term incentive	**257,000**	170,200	26,400	86,800
Miscellaneous	**32,400**	79,700	94,100	(47,300)
	2,042,800	2,111,800	1,989,100	(69,000)
Less: Income taxes	**592,400**	612,400	606,700	(20,000)
Less: Part VI.1 tax adjustment	**12,814,000**	2,589,000	(221,300)	10,225,000
Total non-regulated (net of tax)	**$ (11,363,600)**	$ (1,089,600)	$ 1,603,700	$ (10,274,000)

1 The Performance Share Unit (PSU) was introduced in 2013, and the full expense associated with the Plan has been designated as non-regulated. The expense associated with the PSU Plan is not billed to Newfoundland Power by Fortis, which is why it was not included in the Intercompany Transactions Report.

In the table above the most significant fluctuation between 2013 and 2012 pertains to the Part VI.1 tax adjustment. This tax adjustment results from the payment by Fortis of dividends on its preferred shares. The Company has noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.'s corporate tax planning and preferred share dividend payment, and the Company's capacity to cover this tax.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2013 this represents an addition to non-regulated expenses (before tax adjustment) of $257,000 (2012 - $170,200). Details on the short term incentive payouts are included in this report under the heading Short Term Incentive (STI) Program.

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The income tax rate used by the Company for calculating total non-regulated expenses net of tax is 29.0% which agrees with the Company's statutory rate as identified in the 2013 annual report.

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

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Regulatory Assets and Liabilities

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

Regulatory Assets and Liabilities

The following table summarizes Regulatory Assets and Regulatory Liabilities for 2012 and 2013:

(000's)	2013 Actual	2012 Actual	Variance 2013-2012
Regulatory Assets			
Rate stabilization account	**$ 12,407**	$ 19,529	$ (7,122)
OPEBs asset	**42,048**	45,552	(3,504)
Pension deferral	**1,409**	2,537	(1,128)
Cost recovery deferral	**3,150**	4,726	(1,576)
Cost of capital cost recovery deferral	**1,658**	2,487	(829)
Revenue shortfall deferral	**3,172**	-	3,172
Deferred GRA costs	**644**	-	644
Conservation and demand management deferral	**2,937**	339	2,598
Optional seasonal rate revenue and cost recovery account	**134**	130	4
Employee future benefits	**133,096**	175,056	(41,960)
Demand management incentive account	**383**	-	383
Deferred income taxes	**171,212**	166,817	4,395
	$ 372,250	$ 417,173	$ (44,923)
Regulatory Liabilities			
Weather normalization account	**$ 7,081**	$ 6,549	$ 532
Future removal and site restoration provision	**130,693**	126,329	4,364
Demand management incentive account	**-**	785	(785)
Excess earnings	**68**	-	68
	$ 137,842	$ 133,663	$ 4,179

<u>Rate stabilization account</u>

The Rate Stabilization Account ("RSA") primarily relates to changes in the cost and quantity of fuel used by Hydro to produce electricity sold to the Company. On July 1st of each year customer rates are recalculated in order to amortize the balance in the RSA as of March 31st over the subsequent 12 month period. The rates for July 1, 2013 were approved by the Board in P.U. 23 (2013). The RSA regulatory asset of $12,407,000 represents a current portion of $7,136,000 and a non-current portion of $5,271,000.

As of December 31, 2013, there was a charge to the RSA of $7,836,600 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007) and P.U. 43 (2009).

Pursuant to P.U. 31 (2010) the Board approved the Company's proposal to create an Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) as of January 1, 2011. This account consists of the difference between the actual other post-employment benefit expense for any year from that

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approved for the establishment of revenue requirement from rates. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. As of March 31, 2013, the credit balance of $452,200 in the OPEBVDA account was credited to the RSA in accordance with P.U. 16 (2013).

Pursuant to P.U. 43 (2009) the Board approved the Company's proposal to create a Pension Expense Variance Deferral Account (PEVDA) as of January 1, 2010. This account consists of the difference between the actual pension expense in accordance with GAAP and the annual pension expense approved for rate setting purposes. The Company will charge or credit any amount in this account to the RSA as of March 31 in the year in which the difference relates. As of March 31, 2013, the balance of $2,081,909 in the PEVDA account was credited to the RSA in accordance with P.U. 16 (2013).

Pursuant to P.U. 13 (2013) the Board approved the Company's proposal to transfer the annual balance accrued in the Weather Normalization Reserve account in the previous year to the RSA account on March 31 of the subsequent year. As of March 31, 2013 $127,402 was credited to the RSA in accordance with P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account and the Optional Seasonal Rate Revenue and Cost Recovery Account as approved by the Board.

Other-post employment benefits

The Other Post-Employment Benefits ("OPEB") asset represents the cumulative difference between the OPEB expense recognized by the Company based on the cash basis and the OPEB expense based on accrual accounting required under Canadian Generally Accepted Accounting Principles ("GAAP"). In P.U. 43 (2009) the Board ordered that the Company file a comprehensive proposal for the adoption of the accrual method of accounting for OPEB costs as of January 1, 2011. The report was filed by Newfoundland Power on June 30, 2010. In summary, the Board ordered the approval, for regulatory purposes, of the accrual method of accounting for OPEBs costs and income tax related to OPEBs; recovery of the transitional balance, or regulatory asset, of $52.4 million as at January 1, 2011, over a 15-year period; and adoption of the OPEB Cost Variance Deferral Account. These recommendations were approved by the Board in P.U. 31(2010).

Pension deferral

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

Cost recovery deferral

The Cost Recovery Deferral balance relates to the conclusion of the following regulatory amortizations which expired in 2010: 2005 Unbilled Revenue, Municipal Tax Liability, Depreciation, Replacement Energy, Purchased Power Unit Cost Reserve and 2008 GRA Costs. Expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000. On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of the above mentioned deferrals. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 46(2009). In P.U. 30 (2010), the Board approved the deferred recovery, until a further Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which is to be charged with the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differ from the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. In P.U. 22 (2011), the Board approved the deferred

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recovery, until a further Order of the Board, of an additional $2,363,000 in 2012 due to the conclusion in 2010 of the amortizations. In P.U. 13 (2013) the Board approved amortization of these cost recovery deferrals over three years. Amortization of this account commenced in 2013.

Cost of capital cost recovery deferral

The cost of capital cost recovery deferral account reflects the deferred recovery of $2,487,000 reflecting the difference between the 8.38% return on equity currently in customer electricity rates and the 8.80% return on equity approved in P.U. 17 (2012). In P.U. 13 (2013) the Board approved a three year amortization of the cost of capital recovery deferral. Amortization of this account commenced in 2013.

Deferred general rate application costs

In P.U. 13 (2013) the Board approved the deferral of cost related to 2013/2014 GRA as well as amortization of this deferral over a three year period commencing in 2013. Actual costs incurred and deferred were approximately $965,000 with amortization of $321,000 incurred in 2013.

Conservation and demand management deferral

The Conservation and Demand Management deferral account arose as a result of the Company's implementation of conservation and demand management programs. These costs totaled $1,357,000 (before tax) and the Board ordered pursuant to P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In P.U.43 (2009), the Board approved the Company's proposal to recover the 2009 conservation programming costs over the remaining four years of the five year Energy Conservation Plan through the Conversation Cost Deferral Account. Amortization of this account commenced in 2010.

Pursuant to P.U. 13 (2013) the Board approved the Company's proposed change in definition of conservation program costs and the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. The actual costs incurred and deferred in 2013 were $2,937,000 (before tax). Amortization of this balance will commence in 2014.

Optional seasonal rate revenue and cost recovery account

The Optional Seasonal Rate Revenue and Cost Recovery Account provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study in accordance with P.U. 8 (2011). The optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. In accordance with P.U. 8 (2011), the Company must file an application with the Board for the disposition to the RSA of any balance in this account. The balance at December 31, 2013 was $137,344. This balance was transferred to the RSA on March 31, 2014 pursuant to the Board's approval in P.U. 10 (2014).

Employee future benefits

On November 10, 2011, the Company submitted an application to the Board requesting approval for the January 1, 2012 adoption of US GAAP for regulatory purposes. On December 15, 2011 pursuant to P.U. 27 (2011) the Board approved the Company's adoption of US GAAP for general regulatory purposes.

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

- The unamortized balances for transitional obligations associated with defined benefit pension plans, and the majority of the unamortized transitional obligation for OPEBs were required to be recorded as a reduction to retained earnings. The Board ordered that these balances be recorded as a regulatory asset to be amortized through 2017 as an increase to employee future benefits expense.
- The unamortized balances related to past service costs, actuarial gains or losses, and a portion of the unamortized transitional obligation for OPEBs were required to be recorded as a reduction to equity and classified as accumulated other comprehensive loss on the balance sheet. The Board ordered

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that these balances be reclassified as a regulatory asset. The amortization of these balances will continue to be included in the calculation of employee future benefit expense.

- The period over which pension expense is recognized differed between Canadian GAAP and U.S. GAAP. Therefore the cumulative difference was recorded as a regulatory asset to be recovered from customers in future rates. The disposition of balances in this account will be determined by a further order of the Board.

In P.U. 27 (2011) the Board ordered that Newfoundland Power *" apply to the Board for approval of changes to existing regulatory assets and liabilities and the creation of any new regulatory assets and liabilities, along with appropriate definitions of the accounts related to these regulatory assets and liabilities, that will be required to effect the adoption of US GAAP".*

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

i. Opening balances for regulatory assets and liabilities associated with employee future benefits which arise upon Newfoundland Power's adoption of US GAAP effective January 1, 2012 and

ii. a definition of the account related to those regulatory assets and liabilities

The Company's Application included a comparison between the actual opening regulatory assets and liabilities as of January 1, 2012 related to employee future benefits which created a regulatory asset of $131,249,000 (comprising the Defined Benefit Pension Plan regulatory asset of $109,197,000, OPEBs Plan regulatory asset of $21,116,000 and the PUP regulatory asset of $936,000).

In P.U. 11 (2012) the Board approved the creation of a regulatory asset to reflect the accumulated difference to December 31, 2012 in defined benefit pension expense calculated under US GAAP and Canadian Generally Accepted Accounting Principles. In P.U. 13 (2013) the Board approved the recognition of defined pension expense in accordance with U.S GAAP and a regulatory asset of $12,400,000, resulting from P.U. 11 2012, to be amortized over 15 years commencing in 2013.

As of December 31, 2013 the regulated asset for employee future benefits was $133,096,000.

Deferred income taxes

Deferred income tax assets and liabilities associated with certain temporary timing differences between the tax basis of assets and the liabilities carrying amount are not included in customer rates. These amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company has recognized this deferred income tax liability with an offsetting increase in regulatory assets. Net regulatory asset for deferred income taxes at December 31, 2013 was $171,212,000.

Weather normalization account

The Weather Normalization reserve reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal and actual weather conditions. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year. As at December 31, 2012, the non-reversing Degree Day component has been fully amortized. The balance in the Weather Normalization reserve represents the reversing component, which should tend to zero over time.

In P.U. 13 (2013) the Board approved the amortization of the December 31, 2011 year-end balance of the weather normalization account of $7,006,000 ($5,020,000 after future income tax) over a three year period

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beginning in 2013, representing an amortization of approximately $2,335,000 ($1,673,000 after future income tax) each year. In addition, commencing in 2013, P.U. 13 (2013) also approved the disposition of the balance accrued in the weather normalization account in the previous year to the Rate Stabilization Account at March 31 of the following year. In P.U. 11 (2014) the Board approved the December 31, 2013 net regulatory liability balance in the weather normalization account of $7,081,000 ($5,058,185 net of future income tax).

Future removal and site restoration provision

The Future Removal and Site Restoration Provision account represents amounts collected in customer electricity rates over the life of certain property, plant, and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. The balance is calculated using current depreciation rates. For 2013 the balance in this account was $130,693,000 (2012 - $126,329,000).

Demand management incentive account

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2013, the variation in the account was a regulatory asset of $383,085. This balance was transferred as a debit to the RSA on March 31, 2014 pursuant to the Board's approval in P.U. 7 (2014).

Excess earnings

Excess earnings are the earnings that exceed the upper limit of the allowed range of return on rate base of 8.10% approved by the Board in P.U. 13 (2013).

As a result of our analysis we note that the average rate base originally filed in Return 3 and Return 13 uses an understated average rate base balance of $915,612,000. The understated average rate base produced an excess earnings liability of $68,000 ($49,000 after tax).

An average rate base of $915,820,000 was subsequently filed by the Company in Schedule D of its 2015 Capital Budget Application (see Return on Rate Base and Equity, Capital Structure and Interest Coverage for details of revisions). This revised rate base produces excess earnings of $42,000 ($33,000) after tax. In discussions with the Company they have determined the additional excess earnings of $26,000 ($16,000 after tax) reported in Return 13 are immaterial to file a revised return. This represents a benefit to the customer.

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2013 are unreasonable.

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Pension Expense Variance Deferral Account

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

In P.U. 43 (2009) the Board approved the creation of the Pension Expense Variance Deferral Account. PEVDA was created to capture the difference between the annual pension expense approved for the test year revenue requirement and the actual pension expense computed in accordance with generally accepted accounting principles for any subsequent year. The purpose of the PEVDA is to adjust the variability related to factors outside of the Company's control, primarily due to changes in discount rates. The balance in the PEVDA is a charge or credit to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

The 2013 PEVDA was calculated at $2,081,909. This balance was transferred to the Rate Stabilization Account on March 31, 2013 in accordance with P.U. 43 (2009).

We confirm that the 2013 PEVDA is calculated in accordance with P.U. 43 (2009).

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Other Post-Employment Benefits Cost Variance Deferral Account

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

In P.U. 31 (2010) the Board approved the creation of the Other Post-Employment Benefits Cost Variance Deferral Account. OPEBVDA was created to capture the difference between the annual Other Post-Employment Benefits ("OPEBs") expense approved for the test year revenue requirement and the actual OPEBs expense computed in accordance with generally accepted accounting principles for any subsequent year. The purpose of the OPEBVDA is to adjust the variability related to factors outside the Company's control, primarily due to changes in discount rates. The OPEBs expense for the year is the total of (i) the OPEBs expense for regulatory purposes for the year, and (ii) the amortization of OPEBs regulatory asset for the year. The balance in the OPEBVDA is a charge or credit to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

The 2013 OPEBVDA was calculated at $452,200. This balance was transferred to the Rate Stabilization Account on March 31, 2013 in accordance with P.U. 31 (2010).

We confirm that the 2013 OPEBVDA is calculated in accordance with P.U. 31 (2010).

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Optional Seasonal Rate Revenue and Cost Recovery Account

Scope: ***Review of calculation of the Optional Seasonal Rate Revenue and Cost Recovery Account and assess compliance with P.U. 8 (2011) and P.U. 13 (2013)***

In P.U. 8 (2011) the Board approved Rate #1.1S Domestic Seasonal – Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates (the "TOD Rate Study"). On December 31st of each year from 2011 until further order of the Board, this account is to be charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal – Optional and the Time-of-Day Rate Study. In P.U. 13 (2013) the Board approved to maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until the next general rate application.

In accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the first day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. This application for the disposition of the 2013 balance was filed February 26, 2014, within the deadline.

The Optional Seasonal Rate Revenue and Cost Recovery Account balance at December 31, 2013 was $137,344. This balance was transferred to the Rate Stabilization Account in March, 2014 as approved in P.U. 10 (2014).

We confirm that the 2013 Optional Seasonal Rate Revenue and Cost Recovery Account is calculated in accordance with P.U. 8 (2011).

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Productivity and Operating Improvements

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

On an ongoing basis, Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. According to the information provided by Newfoundland Power, the productivity and operational improvements undertaken in 2013 are as follows:

1. Made capital investments of $82 million of which over 50% were targeted directly to replacing or refurbishing deteriorated and defective equipment.

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

3. Continued work under the Transmission Line Strategy and the Substation Modernization Plan.

4. Continued to install automated meters with remote capabilities in locations that prove difficult to read; 62 meter reading routes have been eliminated to year end 2013.

5. A number of changes were made to materials management structure and processes. Responsibility for the area storekeepers shifted from the area offices to Materials Management to bring renewed focus and more consistent expectations for this role. A new system was implemented which enables online ordering of fire retardant clothing and direct delivery to the employee, which will reduce the time and effort spent by supervisory and warehouse staff. A new requisitioning system has also been implemented.

6. Following the January 11th loss of supply incident, the Company made a number of revisions to its outage response and communication protocol. During large scale outages, a centralized communications hub will bring together Operations, Customer Relations and Corporate Communications representatives. This team will ensure internal and external communication in outage situations is both consistent and timely.

7. A new outage communications software system was deployed late in the 1st quarter. This system, called Informer, provides a number of enhancements, such as customized outage status messages which will improve customer communications.

8. During the 1st quarter, Newfoundland Power added 24 phone lines to receive customer calls for outage information. This will reduce the number of times customers receive a busy signal when contacting the Company during outages.

9. New technology has been used to schedule and dispatch field work for line crews in St. John's since 2011. Based on the success of this pilot, the Company is centralizing dispatch of line work, including new service connections and trouble call response, for all areas in 2013. This involves changes to work processes, roles and technology supporting operations, and is expected to enable customer service and productivity improvements.

10. In June 2013, the Company successfully completed an upgrade to its accounting system, Microsoft Dynamics Great Plains. The last upgrade occurred in October of 2008. Extensive post implementation testing has been completed with no significant issues. The new features of the upgrade will allow for increased efficiency of accounting tasks and improved financial reporting.

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11. Replenishment of stock in the area warehouses from Central Stores at Duffy Place in St. John's has been reorganized on a bi-weekly schedule resulting in improved workflows.

12. Customer self-service at www.newfoundlandpower.com was enhanced during the quarter with the deployment of multiple payment arrangement capability. This feature allows eligible customers with accounts in arrears to propose multiple payment arrangements on multiple dates.

13. In May, the Company began scheduling customer appointments for new service connections in the St. John's region.

14. The Company website was updated to position eBills as the primary billing method for new customers. This is part of the on-going initiative to encourage customers to receive their bills electronically.

15. In preparation for the coming storm season, the Company website has been enhanced to allow customers to report a power outage through the website or through a mobile device, without having to speak to a representative.

16. The Company updated its phone system to allow customers to specify the area for which they want outage information if the phone system is unable to identify the area from which the call originates. Extra phone lines and reconfiguration of the automated menu will also reduce the likelihood of customers receiving a busy signal.

17. The Company purchased new safety management software that provides enhanced abilities to track and manage safety programs.

18. Newfoundland Power implemented improvements to the service contact process for building contractors, enabling more proactive identification and prioritization of requirements such as licenses, permits and easements. The new process has resulted in immediate benefits in reduced call durations and field service wait times.

19. Customer Service System improvements in the 4th quarter enabled customers' equal payment plan requests via the Company's website to be processed automatically, with no involvement of customer service staff.

20. All Newfoundland Power line trucks are now equipped with GPS location tracking and real time connectivity, and all trouble calls and streetlight requests are being dispatched to crews electronically. New service connections are being dispatched electronically in five of the Company's eight operating areas, with the last three areas scheduled to be online in 1st quarter 2014.

Performance Measures

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

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

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The following table lists the principal performance measures used in the management of the company:

Category	Measure	Actual 2011	Actual 2012	Actual 2013	Plan 2013	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.57	2.44	2.23	2.53	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.70	1.72	1.71	1.65	No
	Plant Availability (%)	93.5	94.8	93.0	95.9	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	88.5	86.7	86.0	88.0	No
	Call Centre Service Level (% per second)[2]	80/60	80/60	80/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	80.2	84.5	85.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	1.8	1.7	1.1	1.8	Yes
Financial	Earnings (millions)[3]	$33.7	$36.6	$36.6	$35.3	Yes
	Gross Operating Cost/Customer[4]	$241	$238	$243	$243	Yes

[1] 2013 reliability statistics reported above exclude the impact of the January Newfoundland and Labrador Hydro system problems and the November blizzard in Central and Western. 2012 reliability statistics reported above exclude the impact of Tropical Storm Leslie. 2011 reliability statistics exclude the impact of a storm in December 2011.

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

[3] Excludes $12.8m recovery related to Part VI.I tax

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

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