Grant Thornton
2012 Annual Financial Review of Newfoundland Power Inc.

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

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2012 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"). Below is a summary of the key observations and findings included in our report.

The average rate base for 2012 was $883,045,000 compared to average rate base for 2011 of $876,356,000. The Company's calculation of the return on average rate base for 2012 was 8.10% (2011 - 8.14%) compared to an approved rate of return of 8.14%. The actual rate of return was just below the middle of the range approved by the Board (7.96% to 8.32%). The calculations of average rate base and rate of return on average rate base are in accordance with established practice and Board orders.

The Company's calculation of average common equity for 2012 was $395,793,000 (2011 - $392,266,000). The Company's actual return on average common equity for the year ended December 31, 2012 was 8.98% (2011 - 9.00%). In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2012 the cost of common equity per the Formula was 8.8% (P.U. 17 (2012)). The actual return on average common equity for 2012 was 8.98% as noted above. This return was within the 50 basis point trigger and as such no report was required.

The actual capital expenditures (excluding capital projects carried forward from prior years) was 0.50% under budget in 2012. The capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $2,621,000 (2.96%). However, for each category of expenditure, the variances ranged from an over-budget of 16.40% to an under-budget of 75.55%. Significant variances are explained in our report.

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

Net operating expenses in 2012 increased by $1,773,000 from 2011. The increase is primarily due to an increase in pension and early retirement program costs and the accrual of other post-employment benefits ("OPEBs"). These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2012 are unreasonable.

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

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

Based on our review, the 2012 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with P.U. 43 (2009).

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

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

The Company continues to undertake initiatives aimed at improving reliability of service and efficiency of operations as is summarized in the Section entitled 'Productivity and Operating Improvements'. During 2012 the Company met four out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Plant Availability", "% of Satisfied Customers as measured by Customer Satisfaction Survey", "Trouble Call Responded to Within 2 Hours" "All Injury/Illness Frequency Rate" and "Gross Operating Cost/Customer". The Company excluded the impact of Tropical Storm Leslie from its reliability statistics.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2012 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

Scope and Limitations

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

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

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

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

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

   - advertising,
   - bad debts (uncollectible bills),
   - company pension plan,
   - costs associated with curtailable rates,
   - conservation costs,
   - donations,
   - general expenses capitalized (GEC),
   - income taxes,
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits,
   - travel, and
   - amortization of regulatory costs as per P.U. 32 (2007) and P.U. 43(2009).

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

5. Examine the Company's 2012 capital expenditures in comparison to budgets and prior years and follow up on any significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

6. Review the Company's rates of depreciation and assess their compliance with the Gannett Fleming Depreciation Study dated December 31, 2005. Assess reasonableness of depreciation expense.

7. Review Minutes of Board of Directors' meetings.

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

9. Conduct an examination of the changes to regulatory deferrals.

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

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

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

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

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

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

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

The financial statements of the Company for the year ended December 31, 2012 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 6, 2013. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

System of Accounts

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

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

On April 9, 2012, the Company filed a summary of revisions to its system of accounts with the Board, along with a copy of the revised System of Accounts. In submitting these changes the Company noted that the revisions were mainly due to changes arising from specific Board Orders, as well as adoption of United States Generally Accepted Accounting Principles ("US GAAP"). The revisions consisted of the addition of new accounts, the deletion of older accounts, as well as account description changes.

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

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

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

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

Calculation of Average Rate Base

The Company's calculation of its average rate base for the year ended December 31, 2012 which is included on Return 3 of the annual report to the Board was computed using the Asset Rate Base Method ("ARBM"). The average rate base for 2012 was $883,045,000 which is an increase of $6,689,000 (0.76%) over the average rate base for 2011 of $876,356,000.

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

- agreed all carry-forward data to supporting documentation including audited financial statements and internal accounting records, where applicable;

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

- checked the clerical accuracy of the continuity of the rate base for 2012; and

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

The following table summarizes the components of the average rate base for 2012, 2011 and 2010 (all figures shown are averages):

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

(a) The Company's rate base is determined using the Asset Rate Base Method which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $99,125,000 (2011 - $100,354,000) included in the 2012 rate base consists of average deferred pension costs of $98,871,000 (2011 - $100,089,000) and credit facility costs of $255,000 (2011 - $264,000). The Company has included a schedule of these costs in Return 8.

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

(c) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to P.U. 8 (2011), "on December 31st of each year from 2011 until further order of the Board, this account shall be charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal – Optional and the Time-of-Day Rate Study". The calculation of the 2012 average rate base incorporates $160,000 (2011 - $114,000) related to this deferral account.

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

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

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

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

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

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

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

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

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

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

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

(l) Customer Security Deposits are comprised of security deposits received from customers for electrical services in accordance with the Board-approved Schedule of Rates, Rules and Regulations. The calculation of the 2012 average rate base incorporates $773,000 (2011 - $700,000) related to customer security deposits.

(m) The 2012 average rate base calculation incorporates $3,899,000 (2011 - $3,663,000) of Accrued Pension Obligation. This obligation is a result of executive and senior management supplemental pension benefits comprised of a defined benefit plan and a defined contribution plan. The defined benefit plan was closed to new entrants in 1999.

(n) In P.U. 32 (2007) the Board approved the Company's adoption of the accrual method of accounting for income tax related to pension costs. In P.U. 31 (2010) the Board approved the Company's adoption of the accrual method of accounting for other post employment benefits (OPEBs) costs and income tax related to OPEBs. The balance included future income taxes related to pension costs and OPEBs included in the 2012 average rate base is $283,000 and ($2,984,000) respectively. The remaining balance of the future income tax liability in the amount of $4,384,000 relates to capital assets.

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

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

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

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2012 average rate base and conclude that the average rate base included in the Company's annual report to the Board is accurate and in accordance with established practice and Board Orders.

Return on Average Rate Base

The Company's calculation of the return on average rate base is included on Return 13 of the annual report to the Board. The return on average rate base for 2012 was 8.10% (2011 - 8.14%). Our procedures with respect to verifying the reported return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the rate of return to ensure it is in accordance with established practice and Board Orders. For 2012, the return on average rate base is calculated in accordance with the methodology approved in P.U. 43 (2009).

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

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

The Board approved the Company's rate of return on average rate base of 8.14% in a range of 7.96% to 8.32% for 2012 in P.U. 17 (2012). As noted above, the Company's actual return on average rate base for 2012 was 8.10% which was within the range set by the Board. The actual rate of return for 2010 and 2011 were both within the range set by the Board.

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

Capital Structure

In P.U. 43 (2009) the Board reconfirmed its previous position as per P.U. 32 (2007) regarding the capital structure for Newfoundland Power Inc. and the Board has deemed that the proportion of common equity in the capital structure shall not exceed 45%.

The Company's capital structure for 2012 as reported in Return 24 is as follows:

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

Pursuant to P.U. 32 (2007), the Company did submit a schedule (Return 25) calculating the cost of embedded debt for the current year. It also indicated the variances in interest expense and average debt over the 2010 year in Return 26. The embedded cost of debt for 2012 was 7.48% which represents a 16 bps decrease from 2010 test year embedded cost of debt of 7.64%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in compliance with Board Order P.U. 43 (2009).

Calculation of Average Common Equity and Return on Average Common Equity

The Company's calculation of average common equity and return on average common equity for the year ended December 31, 2012 is included on Return 27 of the annual report to the Board. The average common equity for 2012 was $395,793,000 (2011 - $392,266,000). The Company's actual return on average common equity for 2012 was 8.98% (2011 - 9.00%).

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

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;
- agreed component data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of book common equity per P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007) and P.U. 43(2009).
- recalculated the rate of return on common equity for 2012 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 43 (2009).

In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2012 the cost of common equity was 8.80% as per P.U. 17 (2012). The actual return on average common equity for 2012 was 8.98% as noted above. This return was within the 50 basis point trigger and as such no report was required. P.U. 17 (2012) also approved the establishment of the 2012 cost of capital cost recovery deferral account to allow for the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of the Company's 2010 test year costs.

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

Interest Coverage

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

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

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

In P.U. 43 (2009) the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. The level of interest coverage realized for 2012 is 2.30 times.

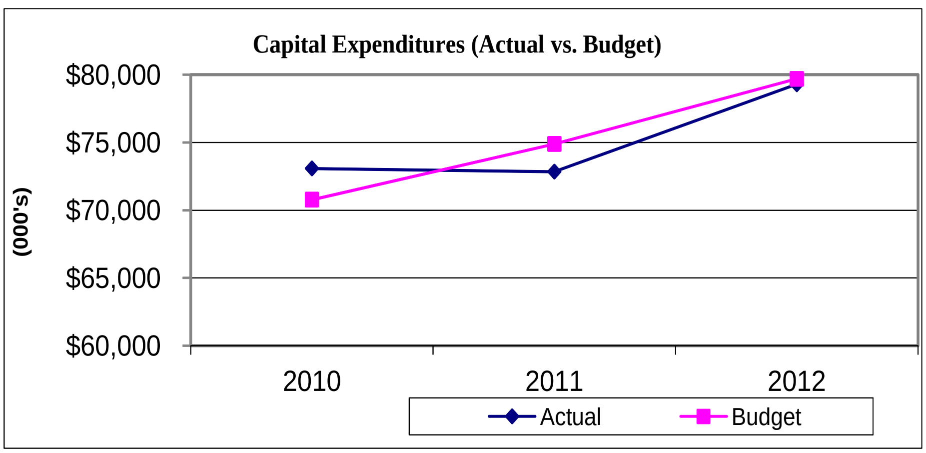
Capital Expenditures

Scope: ***Review the Company's 2012 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures (excluding capital projects carried forward from prior years) for the past three years from 2010 to 2012.

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

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



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

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

(1) Approved by Orders P.U. 26 (2011), P.U. 7 (2012), P.U. 8 (2012), P.U. 22 (2012), P.U. 28 (2012) and P.U. 30 (2012)
(2) The total original budget for the Horse Chops Rewind and Rotor Re-insulation project as noted above was $1,276,000. Total expenditures to December 31, 2012 were $852,000 which is $424,000 below the original budget. The Company noted that the favorable variance was the caused by lower contract prices than were anticipated.
(3) The total original budget for the Rebuild Transmission Lines (2011) project as noted above was $4,745,000. Total expenditures to December 31, 2012 were $3,732,000 which is $1,013,000 below the original budget. Most of the variance is due to the fact that approximately $822,000 was deferred included in the 2012 capital budget.
(4) The total original budget for the Feeder Additions for Growth (2011) project as noted above was $1,281,000. Total expenditures to December 31, 2012 were $633,000 which is $648,000 below the original budget. Most of the variance is due to the fact that work is still be completed and will be included in the 2014 Capital Budget Application.
(5) Total expenditures per the 2012 Capital Budget include the carryover amount of $630,000 for a total of $79,920,000. See note 1 on the previous page.

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

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

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

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

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

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

Generation - Hydro

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

Transmission

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

Distribution

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

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

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

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

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

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

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

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

Telecommunications

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

Allowance for Unforeseen Items

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

General expenses capitalized

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

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2012 capital expenditures are in accordance with the Capital Budget Application Guidelines Policy #1900.6 Sections A and C as noted below:

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

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

- Section C of the guidelines also notes that "should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered". This is interpreted to refer to the variance exceeding 10% in two consecutive years. The variance was (2.73%) in 2011 and (0.50%) in 2012 resulting in no additional reporting requirements.

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

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

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

Capital Expenditure Reports

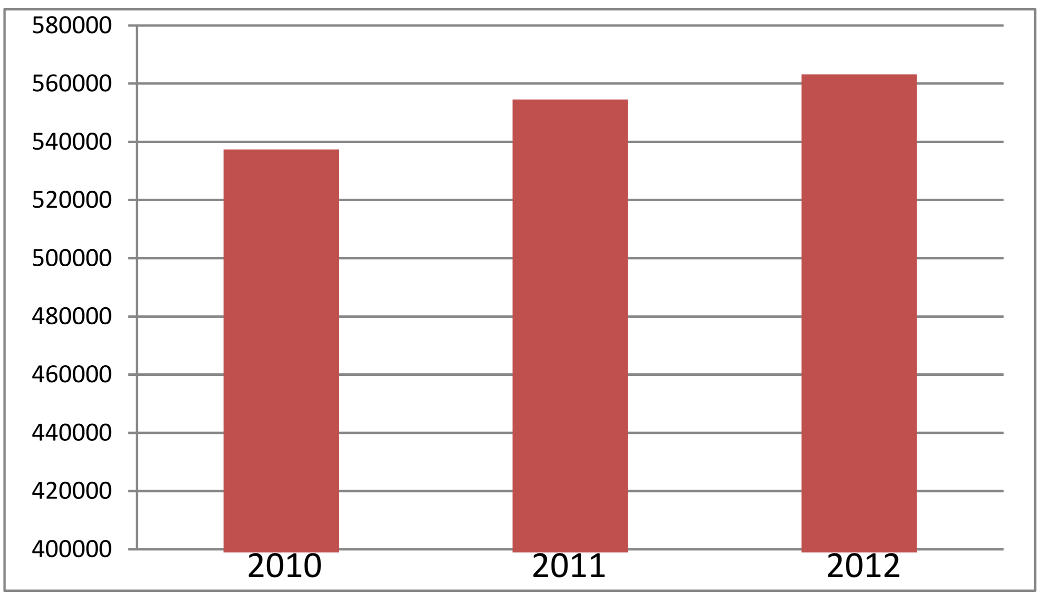
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2012 calendar year.

Revenue

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

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

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



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

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

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

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

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

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

Operating and General Expenses

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

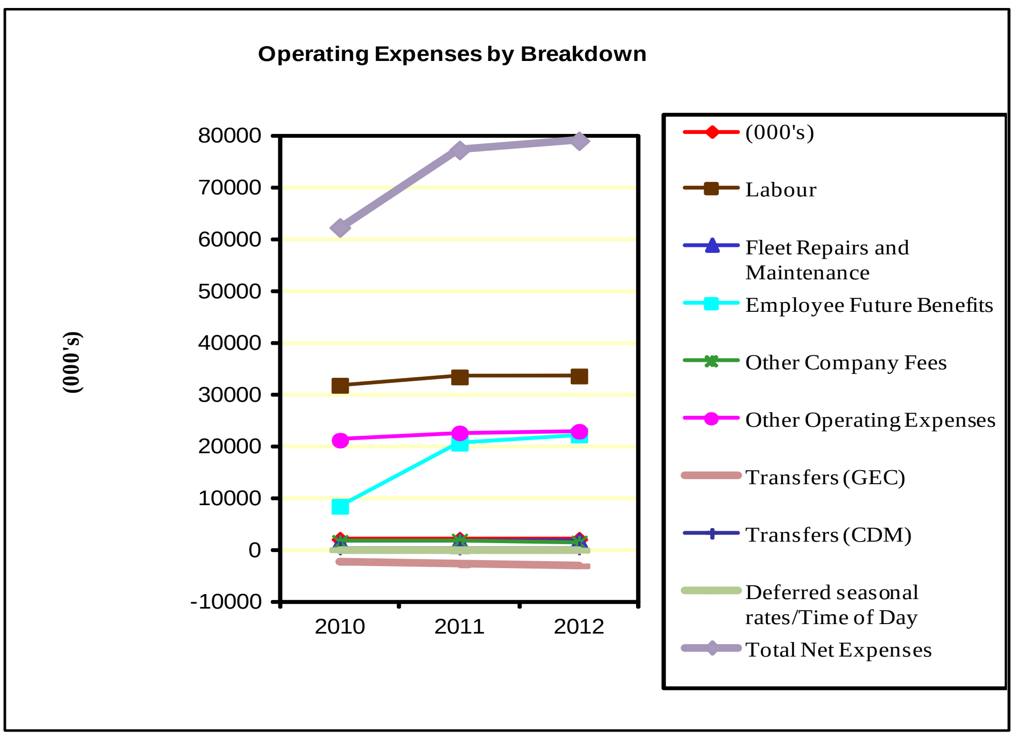
(000's)	Actual 2012	Actual 2011	Actual 2010	Variance 2012 - 2011
Labour	$ 34,052	$ 33,844	$ 32,531	$ 208
Reclass OPEB labour cost	(503)	(493)	(793)	(10)
Total labour	33,549	33,351	31,738	198
Vehicle expense	1,827	1,779	1,504	48
Operating materials	1,577	1,533	1,271	44
Inter-company charges	1,259	1,277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

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

Net operating expenses in 2012 increased by $1,773,000 from 2012. The increase is primarily due to an increase in labour, regulatory, pension and early retirement program costs and OPEBs. These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2012 are unreasonable.

Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2010 to 2012.

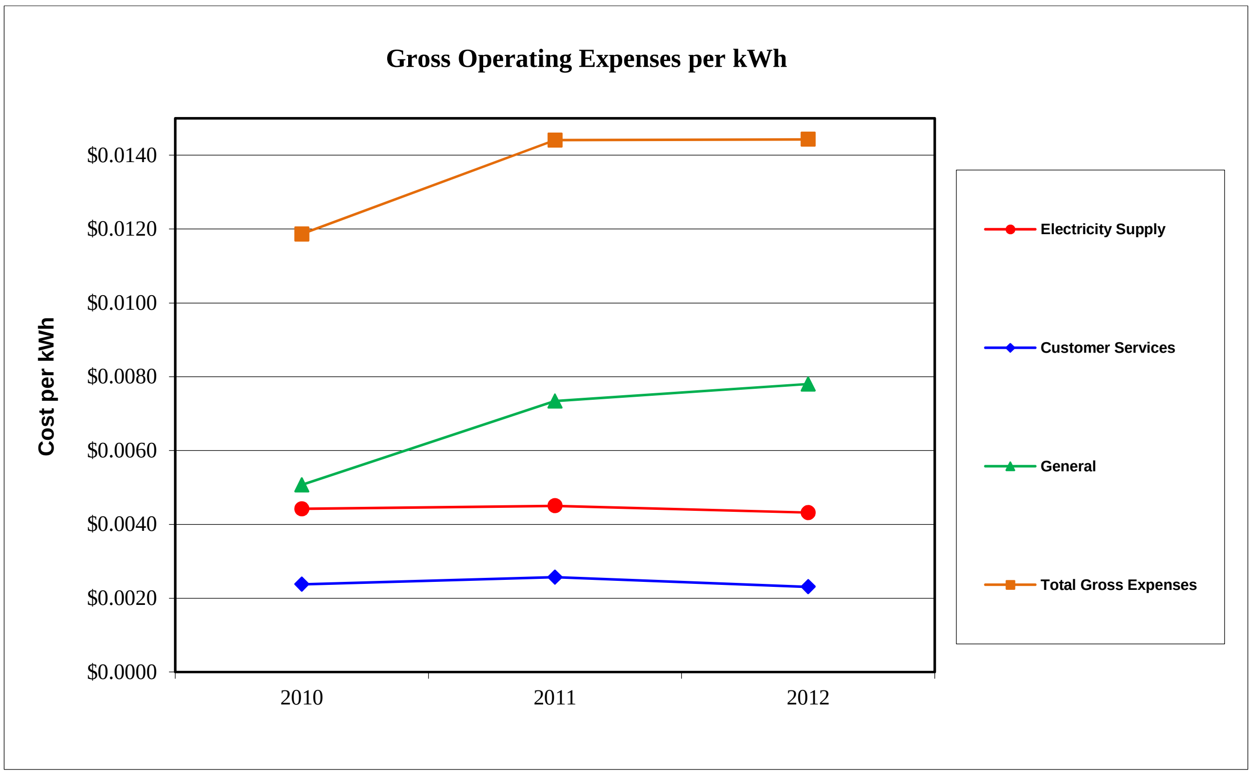
	Actual		
(000's)	**2010**	**2011**	**2012**
Labour	$ 31,738	**$ 33,351**	**$ 33,549**
Fleet Repairs and Maintenance	1,504	**1,779**	**1,827**
Employee Future Benefits	8,381	**20,569**	**22,170**
Other Company Fees	1,513	**1,748**	**1,389**
Other Operating Expenses	21,165	**22,570**	**22,887**
Transfers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



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

Comparison of Gross Operating Expenses to Total kWh Sold

		Electricity Supply		Customer Services		General		Total Gross Expenses	
Year	kWh sold (000's)	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh
2010	5,419,000	$ 23,946	$0.0044	$ 12,872	$0.0024	$ 27,483	$0.0051	$ 64,301	$0.0119
2011	5,552,800	$ 25,009	$0.0045	$ 14,253	$0.0026	$ 40,755	$0.0073	$ 80,017	$0.0144
2012	5,652,200	$ 24,420	$0.0043	$ 13,052	$0.0023	$ 44,097	$0.0078	$ 81,569	$0.0144



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

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

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2010 to 2012 is as follows:

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

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

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

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

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

Our review of salaries and benefits included an analysis of the year to year variances, consideration of trends in labour costs, and discussion of the significant variances with Company officials. As indicated in the above table, total labour costs for 2012 were $4,139,000 (5.94%) higher than 2011.

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

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

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

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

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

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

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

Short Term Incentive (STI) Program

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

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

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

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

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

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

The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. The STI pay for 2012 is established as a percentage of base pay for the three employee groups. For 2012, measures relating to 'earnings', 'SAIDI' and 'customer satisfaction – 1st call resolution', metrics were met, however the 'controllable operating costs/customer', 'customer satisfaction - % satisfied' and 'safety' metrics fell below target.

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

STI Payout

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

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

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

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

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

Executive Compensation

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

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

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

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

Company Pension Plan

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

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

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

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses increased by 9.18% in 2012.

The employer's portion of the contributions to the Group RRSP is calculated as 1.5% of the base salary paid to the plan participants. The increase of approximately $189,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2011 was primarily the result of new hires and wage increases. This was partially offset by retirements and terminations.

Retirement Allowance

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

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

[1] There were 27 retirements in 2012 compared to 22 reitrements in 2011.

[2] In 2011, retirement allowances were included as a part of OPEBs expense upon adoption of the accrual accounting for OPEBs as specified in P.U. 31 (2010).

[3] This represents an accrual which was recorded at the end of 2012 for pending severances/terminations.

Other Post-Employment Benefits ("OPEBs")

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

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

The components of the 2012 OPEBs expense are as follows:

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

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003), P.U. 32 (2007) and P.U. 43 (2009);
- compared intercompany charges for the years 2010 to 2012 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2012 and investigated any unusual items;
- vouched a sample of transactions for 2012 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and,
- reviewed the methodology developed by Fortis Inc. in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2010 to 2012 for charges to and from Newfoundland Power Inc.:

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

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

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

We reviewed Fortis Inc.'s methodology to estimate its recoverable expenses over the first three quarters as well as its "true up" calculation for the 4th quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no changes to the methodology in 2012.

- Fortis Inc. estimated its net pool of operating expenses for 2012 in Q4 2011 as part of its annual business planning process and determined its estimated billings based on the pro-rata portion of such net costs using the estimated assets of subsidiaries. For Quarters 1 through 3 Fortis Inc. billed evenly based upon 25% of the estimated annual amount.
- Similar to 2011, certain staffing and staffing related charges, as well as certain consulting and legal fees, were included in the pool of recoverable expenses. Of these expenses, Fortis deemed 50% of the CEO's, CFO's and Treasurer's salary and related costs to be borne by Fortis Inc. for business development and consequently these costs are excluded from the pool of recoverable expenses. Additionally, certain consulting and legal fees that are attributable to business acquisition activity are excluded. This is consistent with 2011.
- Fortis Inc. used actual year-to-date expenditures up to October and estimated November and December's expenses for the determination of its actual "true up" calculation. Fortis also used actual assets at October 30, 2012 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of November and December's expenditures had a minimal impact.

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

2012 Recoverable Expenses from Fortis Inc.

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

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

As detailed above, trustee agent fees for $52,000 were the only expenses allocated to regulated operations by the Company relating to recoverable expenses. Certain other direct costs were recovered by Fortis Inc. by separate invoicing throughout the year and are detailed in the analysis below of regulated and non-regulated operations.

The analysis below is a review of the intercompany variances related to charges to and from Fortis Inc. as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2010 to 2012 with Fortis Inc.:

Intercompany Transactions

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

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

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

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

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

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

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

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

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

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

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

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

In Order P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2012. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2012.

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

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

Other Company Fees and Deferred Regulatory Costs

The procedures performed for this category included a review of the transactions for 2012 and vouching of a sample of individual transactions to supporting documentation.

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

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

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

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2010 to 2012 is as follows:

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

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

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

Our procedures in this expense category for 2012 included vouching a sample of transactions within the "miscellaneous category" to supporting documentation. Based upon the results of our procedures nothing has come to our attention to indicate that the 2012 expenses are unreasonable.

Conservation and Demand Management (CDM)

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

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

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

Other Operating and General Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating and general expenses by breakdown were also analyzed for any unusual variances between 2012 and 2011 as follows:

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

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

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

Other Costs

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

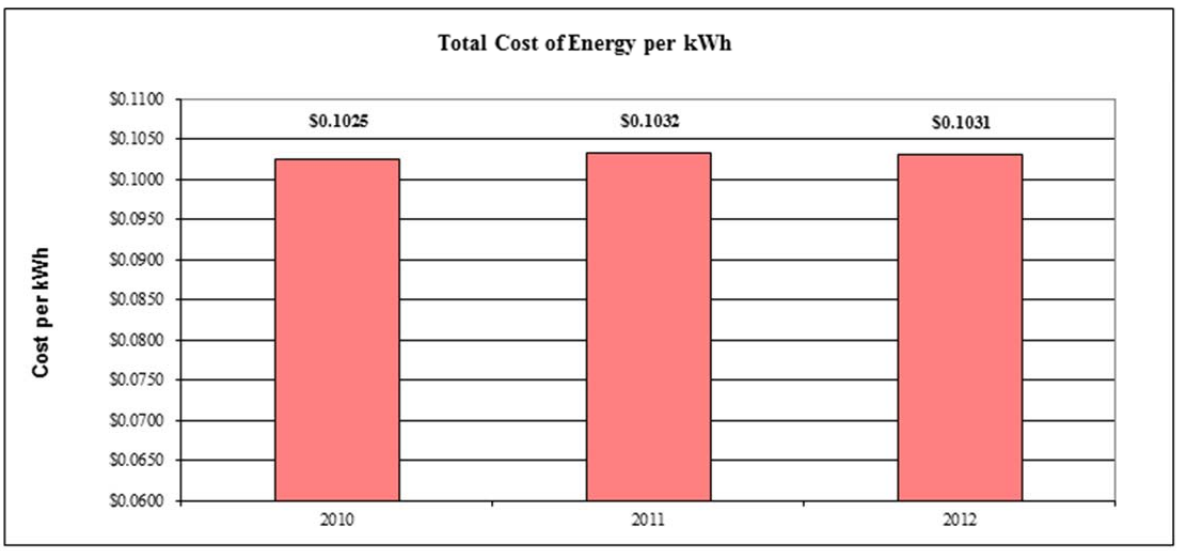
The following table and graph provide the total cost of energy (expressed in kWh) from 2010 to 2012:

(000's)

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

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

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



Purchased Power

We have reviewed the Company's purchased power expense for 2012 and have investigated the reasons for any fluctuations and changes. We performed a recalculation of the purchased power to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Depreciation

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

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

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

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

- agreed all depreciation rates to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2012; and,
- assessed the overall reasonableness of the depreciation for 2012.

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

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

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

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

Interest and Finance Charges

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

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

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

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

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

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

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

Income Tax Expense

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

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

Based upon our review of the Company's calculations, and considering the impact of timing differences, nothing has come to our attention to indicate that income tax expense for 2012 is unreasonable.

Costs Associated with Curtailable Rates

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

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

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

Non-Regulated Expenses

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

* assessed the Company's compliance with Board Orders;
* compared non-regulated expenses for 2012 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2012 and investigated any unusual items;
* assessed the reasonableness and appropriateness of the amounts being charged.

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

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

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

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2012 this represents an addition to non-regulated expenses (before tax adjustment) of $170,200 (2011 - $26,400). Details on the short term incentive payouts are included in this report under the heading Short Term Incentive (STI) Program.

The income tax rate used by the Company for calculating total non-regulated expenses net of tax is 29.0% which agrees with the Company's statutory rate as identified in the 2012 annual report.

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

Regulatory Assets and Liabilities

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

Regulatory Assets and Liabilities

The following table summarizes Regulatory Assets and Regulatory Liabilities for 2011 and 2012:

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

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

Rate stabilization

The Rate Stabilization Account ("RSA") primarily relates to changes in the cost and quantity of fuel used by Hydro to produce electricity sold to the Company. On July 1st of each year customer rates are recalculated in order to amortize the balance in the RSA as of March 31st over the subsequent 12 month period. The rates for July 1, 2012 were approved by the Board in P.U. 20 (2012). The RSA regulatory asset of $19,529,000 represents a current portion of $13,912,000 and a non-current portion of $5,617,000.

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

Pursuant to P.U. 31 (2010) the Board approved the Company's proposal to create an Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) as of January 1, 2011. This account consists of the difference between the actual other post-employment benefit expense for any year from that approved for the establishment of revenue requirement from rates . The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. As of March 31, 2012, the credit balance of $488,420 in the OPEBVDA account was credited to the RSA in accordance with P.U. 31(2010).

Pursuant to P.U. 43 (2009) the Board approved the Company's proposal to create a Pension Expense Variance Deferral Account (PEVDA) as of January 1, 2010. This account consists of the difference between the actual pension expense in accordance with GAAP and the annual pension expense approved for rate setting purposes. The Company will charge or credit any amount in this account to the RSA as of March 31 in the year in which the difference relates. As of March 31, 2012, the balance of $3,863,268 in the PEVDA account was credited to the RSA in accordance with P.U. 43 (2009).

Other-post employment benefits

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

Weather normalization account

The Weather Normalization reserve reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal and actual weather conditions. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year. As at December 31, 2012, the non-reversing Degree Day component has been fully amortized. The balance in the Weather Normalization reserve represents the reversing component, which should tend to zero over time. The net balance in the Weather Normalization reserve at December 31, 2012 is a net regulatory liability of $6,549,000 (net of future income taxes, the balance is $4,803,404).

Pension deferral

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

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

Cost recovery deferral

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

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

Cost of capital cost recovery deferral

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

Deferred general rate application costs

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

Conservation and demand management deferral

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

Optional seasonal rate revenue and cost recovery account

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

Employee Future Benefits

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

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

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

and classified as accumulated other comprehensive loss on the balance sheet. The Board ordered that these balances be reclassified as a regulatory asset. The amortization of these balances will continue to be included in the calculation of employee future benefit expense.

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

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

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

i. Opening balances for regulatory assets and liabilities associated with employee future benefits which arise upon Newfoundland Power's adoption of US GAAP effective January 1, 2012 and
ii. a definition of the account related to those regulatory assets and liabilities

The Company's Application included a comparison between the actual opening regulatory assets and liabilities as of January 1, 2012 related to employee future benefits which created a regulatory asset of $131,249,000 (comprising the Defined Benefit Pension Plan regulatory asset of $109,197,000, OPEBs Plan regulatory asset of $21,116,000 and the PUP regulatory asset of $936,000). As of December 31, 2012 the balance in this account was $175,056,000.

<u>Deferred income taxes</u>

Deferred income tax assets and liabilities associated with temporary timing differences between the tax basis of assets and the liabilities carrying amount are not included in customer rates. These amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company has recognized this deferred income tax liability with an offsetting increase in regulatory assets. Net regulatory asset for deferred income taxes at December 31, 2012 was $166,817,000. The 2011 comparative balance was restated to reflect the impact of the adoption of US GAAP and as a result the balance was $164,079,000. This restatement did not impact the rate base or return on average rate base.

<u>Future removal and site restoration provision</u>

The Future Removal and Site Restoration Provision account represents amounts collected in customer electricity rates over the life of certain property, plant, and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. The balance is calculated using current depreciation rates.

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

Demand management incentive account

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

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

Pension Expense Variance Deferral Account

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

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

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

We confirm that the 2012 PEVDA is calculated in accordance with P.U. 43 (2009).

Other Post Employment Benefits Cost Variance Deferral Account

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

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

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

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

Optional Seasonal Rate Revenue and Cost Recovery Account

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

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

In accordance with P.U. 8 (2011), the Company must file an application with the Board no later than the first day of March each year for the disposition to the Rate Stabilization Account of any balance in this account. This application for the disposition of the 2012 balance was filed February 15, 2013, within the deadline.

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

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

Productivity and Operating Improvements

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

On an ongoing basis, Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. According to the information provided by Newfoundland Power, the productivity and operational improvements undertaken in 2012 are as follows:

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

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

3. Replaced over 475 transformers with stainless steel units.

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

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

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

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

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

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

Performance Measures

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

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

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

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

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

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

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

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