Grant Thornton

Board of Commissioners of Public Utilities Financial Consultants Report Newfoundland Power Inc. 2010 General Rate Application Hearing

July 31, 2009

Contents

Introduction and Scope

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"), which was submitted to the Board on May 28, 2009 in support of its 2010 General Rate Application ("GRA").

Scope and Limitations

The detailed scope of our financial review of the Company's pre-filed evidence is as follows:

Review of the following as detailed in Newfoundland Power Inc.'s 2010 General Rate Application:

- Review the proposed accounting changes with respect to the proposal to use the accrual method of accounting for other post employee future benefits ("OPEBs"), including the related income tax.
- Review the proposed Pension Expense Variance Deferral Account.
- Review the proposed elimination of the Automatic Adjustment Formula.
- Review the proposed treatment of various deferral accounts from January 1, 2010.
- Review the proposal to continue use of the Energy Supply Cost Variance clause beyond 2010 and the Demand Management Incentive Account.
- Review the proposal to have the next depreciation study relate to the plant in service as of December 31, 2009.

Review of 2009 and 2010 financial forecasts including the following:

- Examine the Company's financial records to determine whether it complies with the System of Accounts prescribed by the Board.
- Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, return on rate base and regulated return on common equity for the years ended December 31, 2007 to 2008, and forecasts for December 31, 2009 and 2010.
- Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether the proposed estimates for the years ending December 31, 2009 and 2010 are reasonable and appropriate.
- Review the Company's calculation of forecast average rate base for the year ending December 31, 2010.
- Verify the Company's calculation of the proposed rate of return on average rate base and return on common equity for the year ending December 31, 2010.
- Conduct an examination of power supply cost, operating expenses, depreciation, finance charges, income taxes and other revenues to assess their reasonableness and prudence in relation to sales of power and energy and assess compliance with Board Orders where applicable. Review allocation of non-regulated expenses.
- Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2010 test year.

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

- enquiry and analytical procedures with respect to financial information 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 analysis 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 years ended December 31, 2007 and December 31, 2008 have been audited by Ernst & Young LLP, Chartered Accountants. The auditors have expressed their unqualified opinion on the fairness of the statements in their reports for each year. 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.

Other Post Employment Benefits

Newfoundland Power provides defined benefit and defined contribution pension plans and other post employment benefits (“OPEBs”) to its employees. The Company follows the accrual basis of accounting for pensions in accordance with CICA 3461 *Employee Future Benefits.* Under the accrual basis, the Company recognizes pension expense during the employees’ service period to which benefits relate.

Newfoundland Power’s OPEBs include hospital care, prescription drugs, vision care, other medical, life insurance and retirement allowances. For OPEBs, the Company follows the cash basis of accounting (i.e.: an expense is recognized when benefits are paid). In the absence of rate regulation, CICA 3461 requires use of the accrual method of accounting for other employee future benefits effective January 1, 2000.

In P.U. 19 (2003), the Board approved Newfoundland Power’s proposal to continue to use the cash basis for recognizing expenses for other employee future benefits. However, the Board commented that it “is concerned about the potential liability for employee future benefits and is of the view that NP should explore using the accrual method of accounting for these benefits”. The Board ordered the Company to submit, as part of the 2008 GRA, a report which addressed the use of the accrual method as an alternative to the existing treatment for other employee future benefits. In compliance with this Board Order, Newfoundland Power filed ‘A Report on Employee Future Benefits’ as part of its 2008 GRA. As per P.U. 32 (2007), the 2008 cost increase associated with the OPEBs proposal was $7,200,000 which would have required an increase of approximately 1.5% in revenue for 2008. The Settlement Agreement referred to in P.U. 32 (2007) set out the following as being agreed to between the parties with respect to the treatment of OPEBs:

- “*It is recognized that both cash and accrual accounting treatments are in accordance with GAAP and regulatory accounting principles.*
- *In applying regulatory rate making principles, the Parties agree that in considering the accounting treatment for OPEBs, it is appropriate at this time to give more weight to the rate impact on customers of increases in the cost of electricity than to the principle of intergenerational equity.*
- *NP should, therefore, maintain the cash accounting treatment for OPEBs until the next GRA at which time the matter will be further considered by the Board”.*

Based upon the terms of the Settlement Agreement, the Board ordered that Newfoundland Power continue to use the cash basis for recognizing expenses for OPEBs.

As part of its 2010 GRA, Newfoundland Power has filed a “Report on Other Post Employment Benefits.” Included in this report are details on the following items that the Company is proposing:

1. adoption of the accrual method of accounting for OPEBs costs for regulatory purposes commencing in 2010;
2. tax-effecting all of its employee future benefits costs represented by OPEBs expense for regulatory purposes commencing in 2010; and
3. deferring consideration of the transitional obligation of $46,200,000 until a further hearing to be determined by the Board.

The Company has noted that these proposals, if approved by the Board, will require a revenue increase of 1.0% in 2010. The following sections provide a review of each of these proposals.

Accrual Basis of Accounting

As noted, Newfoundland Power proposes to adopt the accrual method of accounting for OPEBs costs for regulatory purposes in 2010. Under the accrual basis, OPEBs costs are recognized as an expense as employees earn the benefits that they will receive after retirement. The Company currently follows the cash basis whereby only amounts paid during the year are expensed. This difference in treatment has resulted in a regulatory asset of $41,074,000 recognized on the Company's balance sheet as at December 31, 2008.

The Company has represented in its 'Report on Other Post Employment Benefits' that the adoption of the accrual basis for OPEBs will result in an estimated increase in 2010 expenses of $5.7 million (expense under the accrual basis of $7.4 million, less expense under the cash basis of $1.7 million). These amounts exclude the effect of income taxes.

The change in policy from the cash basis to the accrual basis will also have an impact on the Company's rate base. Under the accrual method of accounting a liability will exist on the Company's balance sheet. The liability will be equal to the cumulative excess of the OPEBs expensed under the accrual method versus actual payments made. Under the asset rate base method ("ARBM"), adopted by the Company in 2008, the accrued OPEBs liability will decrease Newfoundland Power's rate base. Consistent with the ARBM, Newfoundland Power is proposing that this liability be deducted from its rate base commencing in 2010 upon the adoption of the accrual method of accounting for OPEBs. This treatment is consistent with the inclusion in rate base of assets and liabilities related to the Company's defined benefit and defined contribution pension plans.

Accounting for OPEBs costs using the accrual method is consistent with the Company's accounting for pensions. The Company also contends that accrual accounting for OPEBs expense is the mainstream regulatory practice in Canada. Based upon a survey completed by the Company, 22 out of 24 Canadian Utilities use the accrual method, including Newfoundland and Labrador Hydro ("Hydro") (the Board approved Hydro's adoption of the accrual method for OPEBs under P.U. 7 (2002 – 2003)).

Based upon our review of this issue we note that the Company's proposal of using the accrual method for accounting for other post employment benefits is in accordance with Canadian GAAP and is consistent with the Company's treatment of pension costs. In addition, as noted above, this treatment is consistent with Newfoundland and Labrador Hydro.

Tax Treatment of OPEBs for regulatory purposes

For income tax purposes, the Canada Revenue Agency (CRA) only permits a tax deduction for cash payments in respect of OPEBs. Newfoundland Power is proposing to adopt the accrual method of accounting for income taxes related to OPEBs effective January 1, 2010. Under the accrual method, the timing of recognizing income tax will match the timing that the related expense is recorded under accrual accounting. For example, income tax expense for a particular year is based on the OPEBs expense determined by accrual accounting, which, as noted above, will differ from the cash basis. During periods when the accrual is greater than the cash paid, income tax expense would decrease. Conversely, during periods when the accrual is less than the cash paid, income tax expense would increase.

The impact that this policy has on the 2010 test year is a decrease in income tax expense of $1.7 million. This balance would be recorded on the Company's balance sheet as a future income tax asset. This decrease in income tax expense would partially offset the increase in OPEBs expense. The Company has noted in its report that this treatment is "… consistent with principle of intergenerational equity. To do otherwise would result in one generation of customers bearing the cost and another generation receiving the benefits."

The decrease in revenue requirement from recording this future income tax asset would be partially offset by an increase in average rate base.

In the absence of rate regulation, accrual accounting for income tax is required under GAAP. Currently, Newfoundland Power recognizes future income tax on temporary differences between pension funding and expense and in capital cost allowance in excess of amortization of capital assets. Recording future taxes on OPEBs as proposed would result in consistent treatment as currently used for pensions.

Based on our review, we conclude that recognizing income tax on the accrual basis for OPEBs is in accordance with Canadian GAAP. In addition, we conclude that this treatment is consistent with the treatment of income tax related to pension expense.

Transitional Obligation

Transitional obligations typically arise on the adoption of the accrual method of accounting for employee future benefits. The obligation represents the cumulative difference between accounting treatments up to the implementation date of the accrual method. There are two components of transitional costs related to Newfoundland Power's move to the accrual method of accounting for OPEBs:

1. The first component is the transitional obligation that existed when the Company adopted the accrual method of accounting for financial reporting purposes on January 1, 2000 as required under CICA 3461. The balance of this obligation on January 1, 2000 was $25,133,000 and is being amortized over 17.6 years (estimated remaining service life of covered employees at the time that Section 3461 was adopted). The unamortized balance as at January 1, 2010 will be $10,857,000. Typically the annual amortization of the transitional obligation is included in a company's benefits expense for the year. However, as Newfoundland Power is recording OPEBs on the cash basis for regulatory purposes, this annual amortization is recorded as part of the regulatory asset. As a result the estimated OPEBs regulatory asset at January 1, 2010 will include $14,276,000 in transitional costs amortization.

   The Company is proposing to continue to amortize the remaining $10,857,000 over 7.6 years (original estimated service life at January 1, 2000 of 17.6 years less time period up to January 1, 2010). This annual amortization of $1,428,000 would be included as part of the Company's OPEBs expense under the accrual basis of accounting.

2. As at December 31, 2008 the Company had recorded a regulatory asset of $41,074,000 on its balance sheet related to other employee benefits. This balance represents the difference between what would have been expensed under the accrual method and what was expensed under the cash method from January 1, 2000 (implementation date for CICA 3461) to December 31, 2008. The Company estimates that this cumulative difference will increase to $46,172,000 as at January 1, 2010 (the proposed adoption date for the accrual method of accounting for OPEBs). This balance includes the $14,276,000 in transitional costs amortization indentified above. The Company has estimated that the impact of recovering this regulatory asset would be to increase revenue requirement by 1.6% assuming a five year amortization period (this would decrease to 0.8% assuming a ten year amortization). To minimize the impact on customer rates related to this transitional balance, the Company is proposing that the disposition of this balance be addressed at a subsequent hearing to be determined by the Board. The Company believes that this will allow for an effective phasing in of the recovery of accrued OPEBs liabilities which, in turn, will help moderate the immediate impact of the accounting change on customer rates.

The Company has noted that these proposals would "effectively result in a two stage approach to addressing the Company's OPEBs accounting policy".

We have reviewed the Company's analysis and calculations and conclude that the forecast transitional balance of $46.2 million at January 1, 2010 agrees to calculations prepared by the Company's actuary. We also conclude that if the Board approves the Company's proposals to adopt the accrual method of accounting for OPEBs and defer consideration of the settlement of the transitional balance, the forecast balance of $46.2 million as at January 1, 2010 will not change in subsequent years.

Pension Expense Variance Deferral Account

In the 2010 GRA, the Company is proposing the creation of a Pension Expense Variance Deferral Account. The Company has included the proposed definition of this account in Exhibit 9 of its pre-filed evidence: "This account shall be charged or credited with the amount by which the annual pension expense computed in accordance with generally accepted accounting principles for any year differs from the annual pension expense approved in the latest test year for the establishment of revenue requirement from rates". The disposition of this account would be a charge or credit to the Rate Stabilization Account ("RSA") as of March 31 in the year in which the difference arises. Section II.6 of the Rate Stabilization Clause permits adjustments to the RSA by any amount as ordered by the Board.

In Volume 1, Section 3 of the pre-filed evidence (page 3-24 to page 3-27) the Company has explained that due to current financial market conditions the variability of pension expense is not reasonably predictable. Under the accrual basis of accounting for pension plans, which the Company currently follows, the pension expense for a particular year is based on a number of assumptions, certain of which are not known until the start of the fiscal year in which the expense relates. For example, under CICA 3461 *Employee Future Benefits* the discount rate used to calculate interest cost on the accrued benefit obligation is determined as of the beginning of the period (or the end of the prior period). This means that interest costs included in pension expense for 2010 will be based upon a discount rate determined as of January 1, 2010 (or December 31, 2009).

Changes in discount rates often have a significant impact on pension expense. The Company has noted that "a change in the discount rate used to value pension obligations of +/- 1% will vary Newfoundland Power's pension expense in the next year by approximately +/- $2.3 to $3.4 million." The discount rate used by the Company increased from 5.5% as at December 31, 2007 to 7.5% at December 31, 2008. Discount rates are based on high quality debt instruments with cash flows that match the timing and amount of expected benefit payments and as such are beyond the control of the Company. The use of the deferral account as defined above will ensure that any variances in pension expense due to changing assumptions, such as discount rates, will be adjusted in customer rates through the inclusion in the RSA.

In addition to the impact that a change in the discount rate has on pension expense, OPEBs expense is also impacted when using the accrual basis of accounting. Currently the Company follows the cash basis of accounting for OPEBs, but as discussed earlier in this report, it is proposing to move to the accrual basis. In response to CA-NP-189 the Company noted that "Newfoundland Power's proposal to recognize costs associated with OPEBs on an accrual basis will not result in an expense risk analogous to the pension risk discussed at pages 3-20 to 3-27 [Volume 1, Section 3 of the Company's pre-filed evidence]". The Company noted in its response that the OPEBs are unfunded and as such are not impacted by market asset performance. While this is correct, we believe that there is still some risk of variability in the OPEBs expense. Under the accrual basis of accounting, OPEBs expense, like pension expense, is dependent on the discount rate used to calculate interest costs on accrued benefit obligations. Interest costs can be a major component of total OPEBs expense. For example, of the total forecast 2010 OPEBs expense of $7,414,000, $4,827,000 consists of interest costs. However, it should be noted that the total variability related to changes in the discount rate on OPEBs would not be as significant as pensions due to the difference in the balance of the accrued benefit obligation. As of December 31, 2008 the accrued benefit obligation on the funded pension was $190,391,000 versus $59,636,000 for OPEBs. (Note: The $59,636,000 is prior to the adjustment for the unamortized net actuarial loss of $6,277,000 and the unamortized transitional obligation of $12,285,000. The net balance equals the OPEBs accrued benefit obligation of $41,074,000).

We conclude that the use of the Pension Expense Deferral Account will limit the variability of pension expense due to changing assumptions, in particular discount rates. In addition, we conclude that the existing provisions of the Rate Stabilization Clause approved in P.U. 6 (2008) allows for the flexibility to adjust the RSA to allow for the disposition of the balance in this deferral account.

However, we also conclude that the accrued benefit obligation related to OPEBs is subject to variability due to uncertainty regarding assumptions, in particular discount rates. As the Company's proposed definition for the Pension Expense Variance Deferral Account related to pensions only, the variability in OPEBs still exists.

Supply Cost Recovery Mechanisms

In P.U. 32 (2007) the Board approved the Company's proposal to replace the Purchased Power Unit Cost Variance Reserve ("PPUCVR") with the Demand Management Incentive Account ("DMI Account"). In this Order the Board also approved a change to the rate stabilization clause to provide for the recovery of the energy supply cost variance through the rate stabilization account for the period 2008 to 2010. Both of these mechanisms provide the Company with the ability to recover its costs associated with the variability in purchase power costs inherent in the demand and energy wholesale rates. Each of these mechanisms is discussed below.

Demand Management Incentive Account

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Hydro's proposed demand and energy rate structure. This reserve mechanism was the PPUCVR and it was used to limit variability demand supply to 1% of test year demand supply cost. Its definition and inclusion in the Company's system of accounts was approved in P.U. 35 (2005). In P.U. 32 (2007) the Board approved the establishment of the DMI Account to replace the PPUCVR, including approval of a definition of the DMI Account to be included in the Company's System of Accounts. The key difference between the reserves is that the PPUCVR is based on a combination of demand and energy costs, and the variance factor is based on forecasted amounts which are updated each year, while the DMI Account is solely based on demand costs and the variance factor is based on the test year. The DMI Account, as it is solely related to demand management, provides transparency in the purchased power costs variability relating to peak demand. Under the DMI Account, variations in the unit cost of purchased power related to demand are limited to 1% of demand costs reflected in customer rates.

According to P.U. 32 (2007) the Company is required to file an application with the Board no later than the 1st day of March each year for the disposition of any balance in the DMI Account. The Board has the discretion to determine the disposition of the reserve balance, taking into account the Company's response to demand management activities.

The following is a summary of the PPUCVR from 2005 to 2008 and its successor, the DMI Account, for 2008:

Operation of Reserves Table

	PPUCVR			DMI Account	
	2005	**2006**	**2007**	**2008**	**Totals**
(000's)					
Supply Cost Variance (Note 1)	$ 439	$ 2,779	$ 1,003	$ 1,170	**$ 5,391**
Deadband/DMI	588	714	521	529	**2,352**
Customer savings	-	2,065	482	641	**3,188**
Tax Effects	-	(723)	(174)	(215)	**(1,112)**
Net Transfer to Reserve	$ -	$ 1,342	$ 308	$ 426	**$ 2,076**

Note 1: PPUCVR supply cost variance is relative to unit supply cost, while the DMI Account supply cost variance is the variance from test year unit demand supply cost.

Reserve Continuity Table

	PPUCVR				DMI Account
	2005	**2006**	**2007**	**2008**	**2008**
(000's)					
Opening balance	$ -	$ -	$ 1,342	$ 1,650	$ -
Net Transfer to Reserve	-	1,342	308	-	426
Disposition of reserves					
Transfer to RSA	-	-	-	(308)	-
Amortization of reserve	-	-	-	(447)	-
Closing balance	**$ -**	**$ 1,342**	**$ 1,650**	**$ 895**	**$ 426**

In P.U. 32 (2007) the Company approved a 3 year amortization commencing in 2008 of the 2006 after tax balance of the PPUCVR of $1,342,000, or $447,000 per year. Under P.U. 6 (2008), the Board approved the disposition of the 2007 balance of the PPUCVR by a net transfer of $308,000 to the RSA. In P.U. 21 (2009), the Board approved the disposition of the 2008 balance of the DMI Account by a net transfer of $426,000 to the RSA.

As noted in the table above the total combined supply cost variance from 2005 to 2008 was $5,391,000 which resulted in customer savings of $3,188,000.

For 2008 and 2009, the +/-1% range for evaluating the Demand Supply Cost Variance to determine the DMI Account transfer was $528,907 based on a test year billing demand of 1,101,890 kW. For 2010, the 1% range is forecast to be $549,485 based on a test year billing demand of 1,144,760 kW.

In P.U. 32 (2007) the Board ordered that the Company provide a report on the operation of the DMI Account with its next GRA setting out any recommendations for changes if necessary. A report was included in the Supporting Materials of this Application and the Company does not recommend any changes relating to the operation of the DMI Account.

Energy Supply Cost Variance Clause

The Energy Supply Cost Variance Clause ("ESCVC") allows for annual variations from the test year in the 'energy' portion of power supply costs to be deferred for recovery through the RSA in the succeeding years. This mechanism was implemented in order to address the supply cost dynamics that exist on the system with the purpose of capturing the change in energy supply costs related to the difference between the marginal energy supply costs and the average energy supply cost, known as the 'Energy Supply Cost Variance'. In addition, the recovery of variances in energy supply costs through the RSA allows the Company to recover its incurred energy supply costs without the requirement of filing a general rate application.

The following tables present the computation of the cents per kWh and dollar variance of the Energy Supply Cost Variance for 2008 and the forecast for 2009 and 2010:

Energy Supply Cost Variance

	Cents/kWh
Difference in energy cost	
Average Test Year Energy Supply Cost (Note 1)	5.535
Wholesale rate 2nd Block price (Note 2)	8.805
Energy Supply Cost Variance (cents/kWh)	**3.270**

	Actual	Forecast	
	2008	**2009**	**2010**
Weather Normalized Annual Purchases (kWh)	5,088,014,000	5,192,600,000	5,287,300,000
Test Year Annual Purchases (kWh)	5,099,900,000	5,099,900,000	5,099,900,000
Difference	(11,886,000)	92,700,000	187,400,000
Energy Supply Cost Variance (cents/kWh)	3.270	3.270	3.270
Energy Supply Cost Variance (in dollars)	**$ (388,672)**	**$ 3,031,290**	**$ 6,127,980**

Note 1: The average test year cost of energy was determined by applying the wholesale energy rate to the 2008 test year forecast energy purchases.

Note 2: The wholesale rate effective January 1, 2007 of 8.805 cents per kWh is the wholesale rate for forecast supply costs for 2009 and 2010.

The RSA is either increased or reduced by the Energy Supply Cost Variance.

In 2008, the result from the Energy Supply Cost Variance provided a benefit to customers of $388,672 via a transfer to the RSA. This transfer was completed at the end of 2008 to the RSA as contemplated in the approval of the ESCVC in P.U. 32 (2007). The reason for the benefit to customers is because the Company's energy purchases from Hydro in 2008 were lower than the 2008 test year forecast.

The forecast for 2009 is a transfer of approximately $3.0 million to the RSA to be recovered from customers over the period from July 1, 2010 to June 30, 2011. In the absence of the 2010 GRA, the forecast for 2010 would be a transfer of approximately $6.1 million to the RSA which would be recovered over the period from July 1, 2011 to June 30, 2012. However, in the 2010 Application, the Company proposes that the forecast 2010 wholesale supply costs will be rebalanced with customer rates. Consequently, no Energy Supply Cost Variance is forecast for 2010. The effect of balancing the 2010 test year supply costs with revenue from rates accounts for 1.1% of the 6.1% increase proposed in the customer rates effective January 1, 2010.

In P.U. 32 (2007) the implementation of the ESCVC of the RSA was approved for the period from 2008 to 2010 and the Board stated that it would review the operation and impact of the Energy Supply Cost Variance in the RSA in the next GRA.

As part of the Settlement Agreement in the 2008 GRA, the parties agreed to the implementation of the ESCVC but "either Party may seek its extension, modification and non-renewal at either the next GRA or on application to the Board".

The Company provided a report on Energy Supply Cost Variance dated May 2009 as part of its Supporting Materials in this Application and the Company does not recommend any changes to the ESCVC. According to the Company, the ESCVC provides the reasonable recovery of prudently incurred energy supply costs. It indicated that the shortfall in recovery of energy supply costs can be expected to continue as long as load growth continues and the marginal energy supply cost remains higher than the average energy supply cost.

We have reviewed the calculations supporting the DMI account and the ESCVC and conclude that these reserve mechanisms appear to be working in accordance with relevant Board Orders. We also conclude that the Company has complied with the reporting requirements regarding these supply cost recovery mechanisms as ordered in P.U. 32 (2007).

Regulatory Deferral Accounts

As a result of the 2008 GRA, the Company obtained Board approval in P.U. 32 (2007) for the amortization of various regulatory deferral accounts (which included the 2005 unbilled revenue deferral, the municipal tax liability, the deferral of 2006 and 2007 depreciation costs, the replacement energy costs deferral, and the hearing costs deferral), and regulatory reserves (which included the weather normalization reserve, accumulated depreciation reserve variance, and the PPUCVR). With the exception of the five year amortization of the degree day component of the weather normalization reserve and the four year amortization of the accumulated depreciation reserve variance, the amortization period for the deferral accounts and the PPUCVR all end in 2010, the test year for the current application filed with the Board.

In the 2010 GRA, the Company has requested Board approval for the proposed treatment of the 2009 conservation costs associated with customer programming under the 5-year Energy Conservation Plan and the third party costs related to this Application.

Conservation Cost Deferral

Prior to the Company's filing of this Application, the Board in P.U 13 (2009) approved the creation of a Conservation Cost Deferral Account. This account provides for the deferred recovery, until a further Order of the Board, of 2009 costs (net of tax) related to the implementation of the Conservation Plan. These costs were estimated at the time to be $1.4 million (net of tax).

In the 2010 GRA, the Company has indicated that the 2009 costs to be deferred are forecast to be $1,516,000 (pre-tax). The Company is proposing that these costs be amortized over the remaining four years ($379,000 per year) of the five year Energy Conservation Plan.

Based on information included in Table 2-8 (page 2-17) of the Company's evidence and its response to CA-NP-90, the 2009 forecast costs relating to customer programs are $1,536,000. A further breakdown of the costs by customer program is as follows:

Customer Programs	
Residential	
Insulation	$ 554,000
Thermostats	289,000
Windows	405,000
	1,248,000
Commercial	288,000
	1,536,000
Less: customer rebates relating to other programs	(20,000)
	$ 1,516,000

Based on the definition of the Conservation Cost Deferral Account approved in P.U. 13 (2009), "The account shall be charged with the costs incurred in implementing the Customer Program Portfolio. The costs will include such items as detailed program development, promotional materials, advertising, pre and post customer installation checks, application and incentive processing, incentives, trade ally training, employee training and program evaluation costs associated with programs in the Customer Program Portfolio." The definition also indicates that the account will exclude any expenditure that is properly chargeable to plant accounts and that it shall also exclude conservation expenditures that are general in nature and not associated with a specific program in the Customer Program Portfolio.

According to the information included in CA-NP-89, the implementation of the four customer energy programs referred to in the Conservation Plan commenced in June 2009. The costs above associated with these energy programs would include advertising costs to support these programs, updating of the *takeCHARGE!* website to include program details and participation instructions for customers. The Company also anticipates further advertising in the fall to coincide with customer activity with upgrading homes.

The Company also indicated that it added new staff and re-aligned existing staff to support the implementation of the Conservation Plan. This would include training to handle customer inquiries and provide advice and support to customers relating to the programs. It also noted that the development of the necessary business systems to support implementation of the Conservation Plan is ongoing.

It was also noted in the response to CA-NP-89 that the Company continues to work with its trade allies to ensure their familiarity with the programs and the availability of the labour and materials necessary for customer participation.

The Company's proposal to recover these costs over a four year period is consistent with the number of years remaining in the Company's conservation plan.

2010 General Rate Application Costs

With respect to the costs relating to the 2010 GRA, the Company is proposing that these costs, estimated at $750,000, be recovered in 2010 customer rates. The Company has noted that the rates set as a result of this Application are not currently expected to be in effect beyond this time.

In previous Board Orders, the Board has ordered recovery of Application costs over a period of a number of years. However, in each of these cases it was expected that the rates determined in the Applications would be in effect for multiple years. If the Company does not expect that the rates set as a result of this current Application will be in effect beyond 2010, a recovery in 2010 of the full amount of the costs would be consistent with the time period over which the Company expects rates to be in effect.

In P.U. 32 (2007), the Board approved a three year amortization period for the recovery of hearing costs in the amount of $1,250,000. In the completion of our 2008 Annual Review of Newfoundland Power Inc., it was noted that the actual external costs relating to the 2008 GRA were $603,000, and this amount is being amortized at $201,000 per year over the three year period ending 2010. However, 2008 rates were set based on an amortization of $416,667 included in the revenue requirement ($1.25 million over 3 years). The variance between actual and forecast costs related to the 2008 test year resulted from the majority of the issues being addressed in the Settlement Agreement which reduced hearing time.

In this Application, the Company has reduced the forecast costs to be incurred by the Board and the Consumer Advocate to $750,000 as compared to the forecast in 2008 of $1,250,000. However, the forecast for 2010 is $147,000 higher than the actual costs incurred for the 2008 GRA ($750,000 2010 forecast verses $603,000 2008 actual).

Analysis

Table 3-18 included in the Company's pre-filed evidence presents the amortization of the various regulatory deferrals that have been approved in previous Board Orders along with those proposed in this Application and the pro-forma annual impact on revenue requirement including the income tax effects for 2009 to 2013. In the table presented below we have included the remaining amortization of $201,000 relating to the 2008 hearing costs that were omitted from the information presented by the Company.

(000's)	2009	2010	2011	2012	2013
Revenue Deferrals					
2005 Unbilled Revenue	$ (6,893)	$ (6,791)	$ -	$ -	$ -
Municipal Tax Liability	(1,362)	(1,362)	-	-	-
Cost Recovery Deferrals					
Depreciation	5,764	5,679	-	-	-
Replacement Energy	598	598	-	-	-
Purchased Power Unit Cost Reserve	(688)	(688)	-	-	-
Weather Normalization Reserve	2,101	2,101	2,101	2,101	
Conservation Cost Deferrals	(1,516)	379	379	379	379
2008 Application Costs	201	201			
2010 Application Costs		750	-	-	-
Revenue Requirement Impacts	$ (1,795)	$ 867	$ 2,480	$ 2,480	$ 379

As indicated above, the total impact of the amortization of the various revenue and cost recovery deferrals is an increase in the revenue requirement of $867,000 for the 2010 test year. The information in the table also indicates that the conclusion of all regulatory amortizations that were approved for the period 2008 to 2010 and the Company's proposed treatment of 2010 Application Cost creates a net increase in the Company's costs for the 2011 to 2012 period noted above.

The Company has indicated that it does do not expect the rates set as a result of this Application to be in effect beyond 2010. If the rates were to apply to future years, the result of the conclusion of the regulatory amortizations in 2010 would not negatively impact customers but would result in an increase in revenue requirement for Newfoundland Power that is not reflected in rates proposed for 2010.

Automatic Adjustment Formula

In P.U. 16 (1998-99) and P.U. 36 (1998-99) the Board ordered the use of the automatic adjustment formula to set an appropriate rate of return on rate base for the Company on an annual basis ("the Formula"). In P.U. 19 (2003) the Board ordered the continuation of the use of the Formula to set the rate of return on average rate base and therefore customer rates for 2005 to 2007. This decision also included the move to the ARBM and the use of the three most recent, rather than the two previously specified series of long term Government of Canada bonds in determining the risk-free rate. In P.U. 32 (2007) the Board approved changes to the Formula to reflect the full adoption of the ARBM for calculating average rate base and ordered the continued use of the Formula for a period of not more than three years following the 2008 test year.

In the 2010 GRA the Company is proposing to discontinue the use of the Formula to calculate adjustments to the Company's rate of return on average rate base and customer rates in years subsequent to 2010. The Company's rationale, as noted in Volume 1, Page 3-18 of the Company's Application, is that "Since P.U. 32 (2007), financial market conditions have materially changed. These changing conditions have, in turn, affected the fairness of the returns on equity yielded by use of the Formula." This issue was addressed in greater detail in the report "Capital Structure and Fair Return on Equity' included in Volume 2, Tab 10 of the supporting materials to the Company's Application.

When the use of the Formula was first approved in P.U.16 (1998-99), the Board noted the following (Source: P.U. 16 (1998-99), page 103): *"the Board is of the view that there is merit to a formula, in light of the cost burden of a full cost of capital hearing and the potential savings to consumers which could be realized. The Board also believes that the adoption of an automatic adjustment mechanism will create greater predictability, which will thereby reduce the risk of regulatory uncertainty. In the opinion of the Board, a mechanism to facilitate an annual review at modest costs will be of benefit to the ratepayer and to the Company."*

P.U. 16 (1998-99) also addressed the fact that circumstances could change "so as to render the use of the automatic adjustment formula to be inappropriate." The Board went on to provide examples of such circumstances on page 104 of P.U. 16 (1998-99):

- *a. "deterioration in the financial strength of the Company, resulting in an inappropriately low interest coverage;*
- *b. changes in financial market conditions which would suggest that the Formula is not accurately reflecting the appropriate return on equity; and*
- *c. fundamental changes in the business risk of the Company."*

The appropriateness of the Company's proposal to discontinue the use of the Formula will be reviewed by the "cost of capital" experts participating in this hearing.

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

Calculation of Average Rate Base

The Company's calculation of its forecast average rate base for the years ending December 31, 2009 and 2010 are included on Exhibit 3 Page 5 of 9 and Exhibit 6 of the pre-filed evidence. Our procedures with respect to verifying the calculation of average rate base were directed towards the assessment of the reasonableness 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 prior years audited financial statements and internal accounting records, where applicable;

- agreed forecast data (capital expenditures; depreciation; etc.) to supporting documentation to ensure it is internally consistent with pre-filed evidence and other areas of the forecast;

- checked the clerical accuracy of the continuity of the rate base as forecast for 2009 and 2010;

- recalculated the forecast rate base for 2009 and 2010; and,

- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act and relevant Board Orders to ensure it is in accordance with established policy and procedure and follows the ARBM as approved in the 2008 GRA.

In 2003 the Company was ordered to move toward the ARBM for determining its rate base which included incorporating average deferred charges into the calculation of rate base.

Pursuant to P.U. 32 (2007), the Board approved the Company's proposal to complete its transition to the ARBM commencing January 1, 2008. The specific adjustments included in the Average Rate Base are as follows:

- Inclusion in rate base of "other assets and liabilities" relating to customer finance programs receivable, customer security deposits, accrued pension liability and municipal tax liability.
- Exclusion in rate base of unamortized debt issue costs. This is now included in the calculation of the Company's weighted average cost of capital ("WACC").
- The Company also updated its calculations for 2008 with respect to the following: funds used during construction; cash working capital; and materials and supplies.

Effective January 1, 2008, the Company adopted the new CICA Handbook Section 3031 – *Inventory* and reclassified inventories of $4.3 million (2007 - $4.1 million) to the account *capital assets - construction materials* on the balance sheet as they are held for the development, construction, maintenance and repair of other capital assets. As at December 31, 2008, $4.3 million (2007 - $4.1 million) in construction materials were included in Plant Investment for financial reporting purposes but have been excluded from the Plant Investment component of the average rate base. Consistent with prior year's calculation, these inventories are included in the materials and supplies component of the average rate base. The Company has stated that it intends to reconcile all its financial reporting and regulatory differences at one time due to the number of accounting changes expected during the Company's transition to International Financial reporting Standards ("IFRS") in 2011.

The following table summarizes the 2010 rate base as existing and as proposed:

(000's)	Existing	Impact		Proposed
Net Plant Investment	$ 754,814	$ 138	(1)	$ 754,952
Add:				
Deferred Charges	104,130	-		104,130
Weather Normalization Reserve	2,000	-		2,000
Deferred Energy Replacement Costs	192	-		192
Cost Recovery Deferrals	3,447	(190)	(2)	3,257
Customer Finance Programs	1,750	-		1,750
	111,519	(190)		111,329
Deduct:				
2005 Unbilled Revenue	2,309	-		2,309
Accrued Pension Liabilities	3,502	-		3,502
Accrued OPEBs Liability	-	2,837	(1)	2,837
Municipal Tax Liability	683	-		683
Future Income Taxes	3,228	(822)	(1)	2,406
Purchased Power Unit Cost Reserve	224	-		224
Customer Security Deposits	643	-		643
	10,589	2,015		12,604
Average Rate Base Before Allowances	855,744	(2,067)		853,677
Cash Working Capital Allowance	10,145	(879)	(3)	9,266
Materials and Supplies Allowance	4,497	(44)	(3)	4,453
Average Rate Base at Year End	$ 870,386	$ (2,990)		$ 867,396

(1) The proposal to adopt the accrual method of accounting for OPEBs has the following impact on the rate base:

- Net Plant Investment - There is an additional $279,000 included in net plant investment related to the capitalized portion of the forecast OPEBs costs in 2010 (impact on average rate base equals $138,000);
- Accrued OPEBs liability - The accrued OPEBs liability is the average increase resulting from the Company's proposal to adopt the accrual method of accounting for OPEBs; and
- Future Income Taxes - The decrease in future income taxes is a result of the Company's proposal to adopt the accrual method of accounting for income taxes related to OPEBs. The $822,000 represents the average increase in future tax assets related to the OPEBs forecast liability of $5,674,000.

(2) The decrease in cost recovery deferrals relates to the amortization of the conservation costs. As noted previously, $1,516,000 is proposed to be amortized over the four year period commencing January 1, 2010. The $190,000 is the average impact in 2010.

(3) As part of the Application, the Company has updated its calculations of the Rate Base Allowances to reflect changes that occurred since the last detailed review in the 2008 GRA. The impact of the updated calculations resulted in a decrease in the cash working capital

("CWC") allowance primarily due to the Company's revised HST adjustment and a decrease in the CWC factor from 2.1% for the 2008 test year to 2.0% for the 2010 test year. The decrease in materials and supplies allowance is due to the Company's revised expansion factor of 20.2% for the 2010 test year versus 19.4% calculated for the 2008 test year.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the average rate base, and therefore conclude that the forecast average rate base included in the Company's pre-filed evidence is in accordance with established practice and follows the ARBM as approved in the 2008 GRA. We also conclude that the proposed average rate base accurately reflects the Company's proposals with respect to OPEBs, including tax effects thereof, cost deferral accounts and the updated calculations related to the rate base allowances.

Return on Rate Base

Our procedures with respect to verifying the calculation of forecast return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the forecast rate of return to ensure it is in accordance with established practice and Board Orders.

The following table provides the 2007 to 2008 actual return on rate base, the Company's forecast rate of return on rate base for 2009 and 2010 and the upper and lower end of range as set by the Board:

	Actual		Forecast		Proposed
	2007	2008	2009	2010(1)	2010
Actual Return on Average Rate Base	8.07%	8.20%	8.15%	7.27%	9.15%
Upper End of Range set by the Board	8.65%	8.55%	8.55%	8.28%	9.33%
Lower End of Range set by the Board	8.29%	8.19%	8.19%	7.92%	8.97%

(1) Upper and Lower range is assumed to be 18bps +/- of the rate of return on rate base of 8.10% assuming the use of the automatic adjustment formula.

In P.U. 32 (2007) the Board approved a 2008 rate of return on average rate base of 8.37%, in a range of 8.19% to 8.55%. The operation of the Automatic Adjustment Formula in 2009 did not result in a change to the approved rate of return. As noted above, the Company's forecast returns for "Existing 2009 and 2010" are below the lower end of the range. The Company is proposing the Board approve a return on average rate base for 2010 of 9.15%, within a range of 8.97% to 9.33%.

Based upon the results of the above procedures we did not note any discrepancies in the Company's calculation of the return on average rate base, and therefore conclude that the forecast return on average rate base included in the Company's pre-filed evidence has been calculated in accordance with established practice. We also conclude that the proposed rate of return on average rate base accurately reflects the proposals in this Application as well as the Company's targeted return on equity of 11% which will be addressed by cost of capital experts participating in this hearing.

Capital Structure

In P.U. 32 (2007) the Board reconfirmed its previous position regarding the capital structure for Newfoundland Power comprised of 45% equity, 54% debt and 1% preferred equity.

Average forecast common equity for 2009 and 2010 including the proposed average common equity for 2010 per the pre-filed evidence is below the approved maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

In its pre-filed evidence the Company is proposing to maintain a capital structure which is consistent with the structure established by Board Order P.U. 16 (1998-99), P.U. 19 (2003) and P.U. 32 (2007).

Based on our recalculations of the components of the capital structure, the Company's projected average capital structure for 2009 and 2010 is as follows:

			Forecast		Proposed
	2007	2008	2009	2010	2010
Debt	54.79%	54.06%	54.00%	54.81%	54.21%
Preferred Equity	1.19%	1.15%	1.10%	1.05%	1.05%
Common Equity	44.02%	44.79%	44.90%	44.14%	44.74%
Total	100.00%	100.00%	100.00%	100.00%	100.00%

The above table shows that the Company's forecast average common equity for 2009 and 2010 is below the 45% maximum approved by the Board and recommended by the Company's cost of capital expert, Ms. Kathleen McShane, as noted in her direct testimony contained in Volume 2 of the Supporting Materials in the 2010 GRA.

The proposed capital structure for 2010 is consistent with the position confirmed by the Board in P.U. 32 (2007). The above calculations of capital structure are consistent with Exhibit 3 (Page 6 of 9) and Exhibit 11 (Page 6 of 9) presented in the 2010 GRA.

Calculation of Average Common Equity and Return on Average Common Equity

In compliance with P.U. 40 (2005) the Company discontinued the use of the regulated common equity and substituted book common equity in the calculation of return on average common equity beginning in 2006. The Company has noted that to sustain its financial integrity in current market conditions it is targeting a 2010 return on equity of 11%.

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;

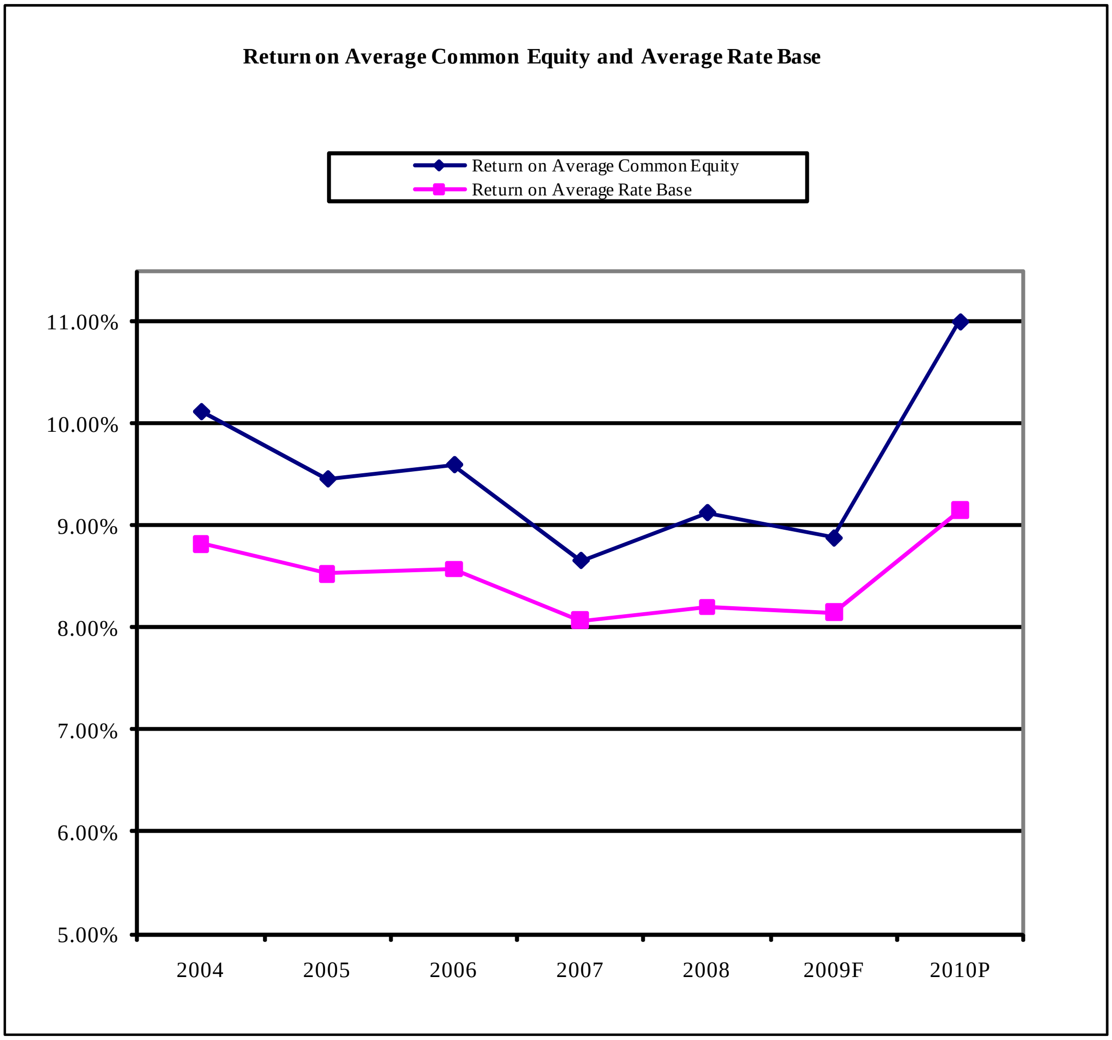
- agreed forecast data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other areas of the forecast;

- checked the clerical accuracy of the continuity of common equity; and,

- recalculated the forecast rate of return on common equity for 2009 and 2010 to ensure it was in accordance with established practice.

The following is a comparison of the actual return on average common equity from 2004 to 2008 and forecast for 2009 and proposed 2010 with the actual return on average rate base for 2004 to proposed 2010.

	2004	2005	2006	2007	2008	Forecast 2009	Proposed 2010
Return on Average Common Equity	10.12%	9.46%	9.60%	8.66%	9.13%	8.88%	11.00%
Return on Average Rate Base	8.82%	8.53%	8.57%	8.07%	8.20%	8.15%	9.15%
Spread between actual returns	1.30%	0.93%	1.03%	0.59%	0.93%	0.73%	1.85%



As demonstrated by the above graph, the proposed 2010 return on average rate base results in an increase in the spread between the return on average common equity and the return on average rate base from 0.93% in 2008 to 1.85% in 2010.

Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the forecast and proposed rate of return on average common equity for 2009 and 2010. The 2010 proposed rate of return on average common equity will be addressed by the cost of capital experts participating in this hearing.

Interest Coverage

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

(000's)	2007	2008	Forecast 2009	Forecast 2010	Proposed 2010
Net income	$ 30,452	$ 32,895	$ 33,064	$ 25,965	$ 42,282
Income taxes	12,176	19,146	16,170	12,584	20,618
Interest on long term debt	33,718	32,334	34,604	35,849	35,849
Interest during construction	(622)	(618)	(366)	(375)	(405)
Other interest	1,781	1,729	641	699	542
Total	$ 77,505	$ 85,486	$ 84,113	$ 74,722	$ 98,886
Interest on long term debt	$ 33,718	$ 32,334	$ 34,604	$ 35,849	$ 35,849
Other interest	1,781	1,729	641	699	542
Total	$ 35,499	$ 34,063	$ 35,245	$ 36,548	$ 36,391
Interest coverage (times)	**2.18**	**2.51**	**2.39**	**2.04**	**2.72**

In P.U. 32 (2007) the Board determined that an interest coverage ratio in the order of 2.5 times is acceptable given the Company's level of risk, capital structure and return on equity. In 2008 interest coverage increased to 2.51 times, which is consistent with the 2008 GRA. The forecast ratios for 2009 and 2010 under existing rates is 2.39 and 2.04 times respectively. As indicated above, the proposals included in this Application result in interest coverage of 2.72 times.

The Board has traditionally considered pre-tax interest coverage to be a primary indicator of creditworthiness in evaluating the relationship between capital structure, rate of return on common equity and interest coverage. However as part of its pre-filed evidence, the Company noted that in recent years credit rating agencies have placed more emphasis on cash flow metrics in their assessment of regulated utilities. The cash flow metrics calculated by the Company were "cash flow interest coverage" and "cash flow debt coverage".

The level of interest coverage will be considered as part of the review of cost of capital during the hearing of this GRA.

Forecasting Methodology and Assumptions

The Company's forecast of revenue and expenses for 2009 and 2010 are based on the expected operating and capital requirements, as well as assumptions, which reflect the best estimate of future economic conditions and events. There are three months of actual data included within the 2009 forecast. The Company has noted in its response to CA-NP-95 that if an updated revenue or expense forecast is required, it will be filed on or before September 29, 2009.

Our approach to this item of the terms of reference focused on three main objectives:

1. to assess the reasonableness of the assumptions made by management with regard to future economic conditions and events;
2. to ensure that the assumptions are properly incorporated into the forecasts; and
3. to review the methodology used by the Company for forecasting revenues and expenses to ensure it is reasonable and appropriate.

Reasonableness of assumptions

The reasonableness of the assumptions used by management was determined based on our general knowledge of economic conditions and Company operations, as well as by reference to and corroboration with information available through independent third parties, including the Conference Board of Canada and Canada Mortgage and Housing Corporation ("CMHC"). The assumptions were also reviewed for consistency with the information included in the pre-filed evidence.

As a result of our review we have determined that the assumptions used by management in forecasting revenue and expenses are based upon and incorporate data from independent sources, where applicable, and are consistent with the information included in the pre-filed evidence.

Since the Company filed its Application, CMHC has released its 2nd Quarter report. We did note that in this report, CMHC has increased its forecast housing starts for 2010 to 2,975 from 2,775.

Incorporation of assumptions into forecasts

The incorporation of the stated assumptions into the forecasts was verified through examination of the exhibits included in the pre-filed evidence, the underlying *Corporate Model* and other supporting schedules and information provided by the Company. Based upon the results of our procedures we can confirm that the assumptions have been properly incorporated into the forecasts.

Methodology

The Company's methodology for forecasting expenses for the 2010 test year is consistent with the approach used in the 2008 hearing.

The guidelines used by the Company in its budgeting process indicate that an inflation factor is to be used when the future cost of a budget item is unknown. If the future cost of an item is known then that would be considered the budgeted cost. The Company indicated that the GDP deflator was primarily used in developing the 2010 forecast of non labour operating expenses and non labour capital costs.

The Company's capital and operating budget is prepared each year as part of an overall planning process. The budget process utilizes a computer system which consists of three modules. These modules include the labour forecast, departmental budgets and capital projects.

Based on the Company's response to CA-NP-96, under the supervision of the manager responsible, the budget coordinator for each department prepares a budget based on the department's expected requirements, a review of recent trends and specific work plans. The manager responsible ensures the budgetary inputs are consistent with work requirements of the department. Departmental staffing inputs are reviewed on a corporate-wide basis based on all operating and capital requirements. Departmental budgets are consolidated by the Finance Department into the corporate forecast and this forecast is reviewed by the executive for approval to ensure it is consistent with corporate priorities.

As a result of our review, we have determined that the overall methodology used by the Company for estimating revenue, expenses and net earnings is similar to the process and methodology used in the 2008 General Rate Application. Our observations and comments with respect to the reasonableness of individual expense estimates and revenue from rates are included within the operating expense and proposed revenue from rates sections of our report.

Capital Expenditures

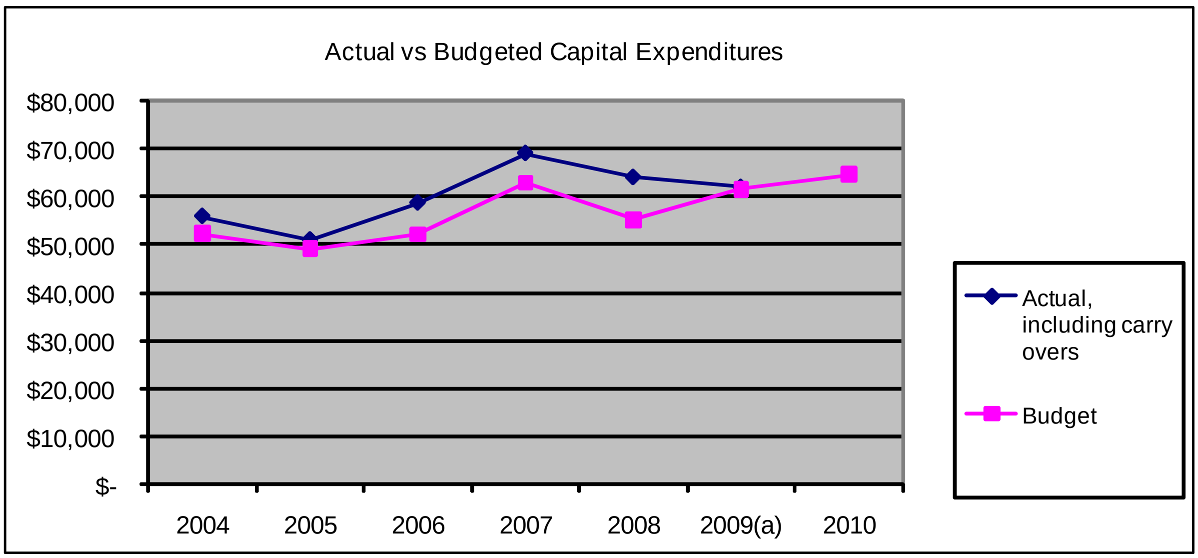
The following table details the actual versus budgeted capital expenditures from 2004 to 2008, including the forecast figures for 2009 and 2010.

	2004	2005	2006	2007	2008	2009(a)	2010
Actual (b)	$ 54,139	$ 50,865	$ 58,482	$ 68,255	$ 62,406	$ 61,945	
Carry over (c)	$ 1,783	$ 147	$ 230	$ 764	$ 1,619		
	$ 55,922	$ 51,012	$ 58,712	$ 69,019	$ 64,025	$ 61,945	
Budget	$ 52,309	$ 49,151	$ 52,220	$ 62,851	$ 55,178	$ 61,571	$ 64,679
Over Budget	6.91%	3.79%	12.43%	9.81%	16.03%	0.61%	N/A

(a) The actual figure for 2009 is the forecast.

(b) Actual represents the actual expenditures on projects approved in that year.

(c) Carry over represents expenditures in subsequent years on projects approved in that year.



The above graph demonstrates that from 2004 to 2008, the Company has been consistently over budget on capital expenditures. According to Capital Budget Application Guideline #1900.6 issued by the Board: "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". It is our understanding that this guideline is applicable commencing with the 2008 capital budget.

From 2004 to 2008, the total capital expenditures have been higher than budget by an average of 9.93% (high: 2008 = 16.03%; low: 2005 = 3.79%).

We have reviewed the significant variances from 2004 to 2008 as part of our annual financial reviews and our comments on these variances are contained in our annual review reports filed with the Board.

In its 2009 Capital Budget Application, the Company requested approval of $61,571,000 for its 2009 capital program. This represents an increase of approximately 12% compared to the 2008 approved capital budget of $55,178,000. The reason for the increase is primarily due to the following two projects:

(1) Replacement of the Rocky Pond hydroelectric plant penstock
(2) Replacement of the power transformer at the Horsechops hydroelectric plant

The total cost associated with these two projects is approximately $7,900,000.

The estimate of 2010 capital expenditures included in this Application is $64,679,000 which is 5% higher than the 2009 capital budget. The reason for the increase is primarily due to the following two asset classes:

(1) Substations – A 2010 project relating to additions due to load growth for a total of $3,650,000, offset partially by a 2009 project related to the replacement of Horsechops Transformer for $1,314,000 as noted above.
(2) Transmissions – An increase over 2009 capital budget of $1,408,000 related to the Transmission Line Rebuild project.

The Company filed a separate Application to the Board on June 19, 2009 with regards to its 2010 capital budget and is requesting approval of its 2010 capital budget in the amount of $64,679,000. This application will be addressed separately from the GRA.

Depreciation

The objective of our procedures in this section was to ensure that the depreciation amounts and rates incorporated in the 2009 and 2010 forecasts are in agreement with the recommendations of the 2006 Update to the Depreciation Study undertaken by Gannett Fleming Valuation and Rate Consultants, Inc.

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

- agreed all depreciation rates, including true-up provision, to those recommended in the depreciation study and the Company's pre-filed evidence;
- recalculated the Company's estimate of depreciation expense for 2009 and 2010; and,
- assessed the overall reasonableness of the estimate of depreciation and true-up amounts for 2009 and 2010.

The 2006 Update determined the annual depreciation accrual rates and the amounts for book purposes applicable to the original cost of the electric plant at December 31, 2005. In P.U. 32 (2007), the Board approved the depreciation rates as recommended in the 2006 Study. These rates became effective January 1, 2008.

The following table indicates the depreciation and related cost recovery deferrals from 2007 to proposed 2010:

	2007	2008	2009F	2010E	2010P
Depreciation	$39,955	$40,649	$41,852	$43,338	$43,341
Cost Recovery Deferrals	(5,793)	-	-	-	-
Amortization of Deferred Cost Recoveries	-	3,862	3,863	3,861	3,861
Net Depreciation	$34,162	$44,511	$45,715	$47,199	$47,202

The deprecation cost is forecast to increase by approximately $1.2 million (2.7%) in 2009 as compared to 2008 and approximately $1.5 million (3.2%) in 2010 as compared to the 2009 forecast amount. The Company has indicated in its pre-filed evidence that the changes in depreciation can be attributable to continued investment in the electricity system. The amortization of deferred cost recoveries of $3,862,000 per year relates to the $11.6 million of deferred 2006 and 2007 depreciation costs that were approved to be amortized over a 3-year period commencing in 2008 based on P.U. 32 (2007).

The Company's depreciation expense for 2008 through 2010 includes a reduction of $174,000 annually as a result of a 4-year amortization of a depreciation true-up of $695,000 as approved in P.U. 32 (2007).

Also included in P.U. 32 (2007), the Board ordered that the Company file a new depreciation study related to plant in service as of December 31, 2010. This study is required to be filed no later than December 31, 2011.

In its 2010 General Rate Application, the Company has proposed that the next depreciation study relate to plant in service as of December 31, 2009. The reason for the request is due to the Company's requirement to file financial statements in 2011 that are compliant with IFRS. The 2011 statements are required to include comparative results for 2010, therefore the Company believes that a study relating to plant in service as of December 31, 2009 would provide detailed information that will be useful in the preparation of these comparative financial statements. This issue is addressed further in this report under the section "International Financial Reporting Standards".

Based on our review of depreciation expense, we conclude that the results and recommendations of the 2006 Updated Depreciation Study have been incorporated into the Company's depreciation estimates for 2009 and 2010.

2010 Test Year Financial Forecast

Based on the evidence included in Exhibit 7 of the Company's pre-filed evidence, combined with the elasticity impact noted in the Company's response to CA-NP-66, Newfoundland Power has indicated it requires an increase in revenue requirement of approximately $34.7 million in 2010. This increase is based on the proposals that the Company has put forward relating to the accounting treatment of items summarized in our report, a rate of return on average rate base of 9.15%, a rate of return on common equity of 11% and an interest coverage of 2.72 times. The factors contributing to the increase can be summarized as follows:

Components of 2010 Proposed Rate Change
($000s)

	Existing (Including Elasticity)	Changes	Proposed	Rate Change %
Return on Rate Base	$ 66,698	$ 12,685	$ 79,383	2.3
Other Costs				
Power Supply Costs	351,942		351,942	
Operating Costs	51,059	1,130	52,189	0.2
Pension and Early Retirement Costs	5,701		5,701	
OPEB Costs		5,930	5,930	1.0
Amortize Depreciation Deferral	3,861		3,861	
Depreciation	43,338	3	43,341	0.0
Income Taxes	13,252	7,915	21,167	1.4
	469,153	14,978	484,131	
Total Costs and Return	535,851	27,663	563,514	
Adjustments				
Other Revenue	(13,800)	128	(13,672)	0.0
2005 Unbilled Revenue	(4,618)		(4,618)	
Other Adjustments	88		88	
	(18,330)	128	(18,202)	
Energy Supply Cost Variance Adjustments	(6,128)	6,128		1.1
2010 Revenue Requirements from Rates	511,393	33,919	545,312	
RSA	40,589		40,589	
MTA	12,944	796	13,740	0.1
Billed to Customers	$ 564,926	$ 34,715	$ 599,641	6.1

In our review we have addressed the major components of revenue requirement noted above, with the exception of the return on equity, and our specific comments on each are outlined in the various individual sections of this report. The appropriateness of the return on common equity will be addressed by the cost of capital experts participating in this proceeding.

Previous sections of this report have reviewed the impacts on revenue requirement relating to OPEBs cost, amortization of deferred accounts and regulatory reserves and depreciation.

The following section reviews forecast operating expenses. Schedule 1 of our report presents the total cost of energy to kWhs sold from 2004 to 2008 and the forecast total cost of energy to forecast kWhs for 2009 and 2010. The table and graph show that the total cost of energy per kWh increased by 22% from 2004 to 2008 ($0.0812 to $0.0992) and is forecast to increase by 6% from 2008 to proposed 2010 ($0.0992 to $0.1052). This increase is primarily attributable to the increase in operating expenses as discussed further in this report as well as the increase in the return on common equity of 11% included in this Application as opposed to 8.95% included in the 2008 GRA.

The effect of all of the factors noted in Newfoundland Power's Application reflect an increased revenue requirement of $34,715,000, which the Company is proposing to obtain by increasing rates effective January 1, 2010 by an average of 6.1%.

Operating Expenses

Using the information in Schedule 1 and Schedule 2 of our report the gross operating costs per customer and net operating costs per customer from 2004 to proposed 2010 is as follows:

	Actual					**Forecast**	**Proposed**
(000's)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Number of customers as at year end	224,464	227,301	229,500	232,262	235,778	238,901	241,431
Gross operating expenses (000's)	$53,794	$55,827	$56,034	$55,168	$51,969	$53,805	$67,434
Net operating expenses (000's)	$51,755	$53,812	$53,996	$53,202	$50,172	$51,905	$65,534
Gross operating expense per customer	$240	$246	$244	$238	$220	$225	$279
Net operating expense per customer	$231	$237	$235	$229	$213	$217	$271

Based on the above information, the gross operating expense and net operating expense per customer decreased by 8.33% and 7.79% from 2004 to 2008 and is forecast to increase by 26.82% and 27.23% from 2008 to proposed 2010, respectively.

Our review of operating expenses was conducted using the breakdown of expenses as outlined in Exhibit 2 of the pre-filed evidence. This exhibit provides details of the actual operating expenses for the years 2007 to 2008 as well as the forecast for 2009 and 2010.

Our review focused primarily on the variances in operating expenses from 2008 to forecast 2009 and 2010. The gross operating expense for 2010 (before transfers to GEC) is forecast to increase by approximately $15,465,000 in comparison to 2008. This increase is primarily related to increases in the following expenses: pension costs - $2,661,000; OPEBs - $5,930,000; labour costs - $2,295,000; advertising - $900,000; taxes and assessments - $760,000; deferred regulatory costs - $752,000; and other company fees - $435,000.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 2 of our report. The table and graph show that the cost per kWh has decreased to $0.0100/kWh in 2008 from $0.0108/kWh in 2004 and is forecast to increase to $0.0126 in 2010. This is primarily due to the increase of gross operating expenses of $15,465,000 as noted above.

Our observations and findings based on our detailed review of the individual expense categories are noted below. Where we have identified unusual trends or other concerns with forecast expenses, we have noted these in the respective sections of our report that follow.

Operating Expenses - Key Variances

Based upon analytical review of Exhibit 2, "Operating Costs by Breakdown" of the Company's pre-filed evidence the following key variances between 2008 and 2010 forecast have been noted along with explanations provided by the Company:

- The Company is forecasting total regular and standby labor costs to increase by $3,001,000 in 2010 versus 2008, representing a 12% increase. According to the Company, the increase can be attributed to conservation related costs, costs associated with management of workforce demographics and labor rate increases. As well, a change in status of employees from temporary to regular in 2009 accounted for $806,000 of the increase.

- Temporary labor is forecast to decrease by $712,000 in 2010 compared to 2008. This decrease can be attributable to change in status of employees from temporary labour to regular labour discussed above and the fact that temporary labor costs include the operating costs associated with Apprentices.

- Taxes and assessments in 2008 were ($10,000) due to timing of recognition of 2008 hearing costs from the PUB. In 2007, the Company estimated $1,250,000 in costs for the 2008 GRA, but actual incurred costs in 2008 were $603,000, resulting in a credit of $647,000. The forecast for 2010 is more comparable with years prior to 2008.

- Insurance is forecast to decrease from $1,344,000 in 2008 to $1,100,000 in 2010, representing a decrease of $244,000. According to the Company, the reduction in insurance costs reflects a combination of insurance market conditions and the benefits of the Company's participation in the Fortis group insurance program.

- Other company fees are forecast to increase from $1,469,000 in 2008 to $1,904,000 in 2010. The reason for the increase can be primarily attributable to increases in arbitration and litigation costs (approximately $100,000), legal costs for regulatory proceedings (approximately $174,000) and the conversion to IFRS (approximately $135,000).

- Advertising costs are forecast to increase $900,000 in 2010 compared to 2008. According to the Company, the primary reason for the increase in advertising is as a result of the Conservation Plan.

- Computing equipment and software costs are forecast to increase $310,000 in 2010 compared to 2008. As per the Company, these costs were lower in 2008 as a result of a one-time change in the accounting treatment of software fees.

- Pension costs are forecast to increase $2,661,000 in 2010 compared to 2008. This account is reviewed in greater detail further in this report.

- Deferred regulatory costs are forecast to increase $752,000 in 2010 compared to 2008. The increase relates to the Company's estimate of third party costs related to this Application and its proposal to fully amortize these application costs in 2010.

Based upon our review and analysis, nothing has come to our attention to indicate that the 2010 forecast operating expenses are unreasonable on an overall basis.

Executive Compensation

The following table provides a summary and comparison of executive compensation for forecast 2009 and 2010 with actuals for 2007 and 2008.

	Base Salary	Short Term Incentive	(Note 1) Other	Total
Forecast 2010				
Total executive group	$ 1,313,250	$ 432,000	$ 152,608	$ 1,897,858
Average per executive (5)	**$ 262,650**	**$ 86,400**	**$ 30,522**	**$ 379,571**
Percentage change per executive	3.0%	3.1%	0.0%	2.8%
Forecast 2009				
Total executive group	$ 1,275,000	$ 419,000	$ 152,608	$ 1,846,608
Average per executive (5)	**$ 255,000**	**$ 83,800**	**$ 30,522**	**$ 369,322**
Percentage change per executive	7.5%	(12.3%)	3.2%	1.9%
2008				
Total executive group	$ 1,185,718	$ 478,000	$ 147,808	$ 1,811,526
Average per executive (5)	**$ 237,144**	**$ 95,600**	**$ 29,562**	**$ 362,305**
Percentage change per executive	5.6%	(4.4%)	(5.6%)	1.8%
2007				
Total executive group	$ 1,122,499	$ 500,000	$ 156,573	$ 1,779,072
Average per executive (5)	**$ 224,500**	**$ 100,000**	**$ 31,315**	**$ 355,814**
Percentage change per executive	3.1%	11.2%	(6.1%)	4.4%

1. The "Other" category of the annual compensation package includes items such as vehicle benefits or car allowance, insurance benefits, and self-directed RRSP employer contributions.

In response to CA-NP-120, the Company referred to a Hay Group report – "Analysis of Executive Compensation" prepared January, 2007 as the basis of setting executive compensation at Newfoundland Power. The Hay Group report recommends that the Company's executive salary be compared to actual salaries paid by the commercial industrial companies reference group. The Company's current executive salary policy is based upon the median of actual salary for the reference group while limiting salaries to 110% of the median.

In 2009, the Company's executive salaries are based on the recommendations of the Hay Group's estimated 2009 market actual salary median as provided in a letter dated November 11, 2008 included in CA-NP-123, and the Company's current executive salary policy.

The base salary increase noted in the table from forecast 2009 to 2010 agrees with the approximate 3% increase indicated in the Company's response to CA-NP-127.

All changes to compensation packages for executives are approved by the Board of Directors based on a recommendation of the Human Resources and Governance Committee as a result of its annual compensation review. The 2009 and 2010 forecast STI payout are based on achieving 100% of targets. Other compensation was estimated by the Company based on a three year average.

Salaries and Benefits

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2007 to forecast 2009 and 2010 is as follows:

	Actual		Forecast	
	2007	2008	2009	2010
Executive group	8.0	8.0	8.0	8.0
Corporate office	25.4	18.6	18.1	19.0
Treasury and finance	69.0	66.4	68.5	69.3
Customer service	67.7	64.7	71.3	75.0
Operations	385.3	393.5	407.6	407.3
	555.4	551.2	573.5	578.6
Temporary employees	71.9	77.0	67.0	72.1
Total	627.3	628.2	640.5	650.7

Pursuant to P.U. 32 (2007) the Company was required to provide detailed information concerning the method used to forecast test year FTEs and labour expense, as well as assumptions used to determine forecast vacancies as part of its next general rate application. The Company has complied with this Order and has included the report "Labour Forecast 2009-2010" as part of its pre-filed evidence for this GRA.

The increase in FTEs from 2008 to forecast 2010 is 22.5 FTEs. The majority of this increase is related to the Customer Service and Operations category with an increase of 10.3 FTEs and 13.8 FTEs, respectively. The forecast for the other categories is fairly consistent with 2008. According to the Company's reporting it is anticipating 15 new hires and 5 retirements in 2009, and 6 new hires and 12 retirements in 2010. The timing of hires and retirements will impact the actual change in FTEs. For example, in 2010 six of the retirements are forecast to occur at year end.

According to the Company's response to CA-NP-110, the increase in forecast 2010 FTEs is primarily driven by new work requirements and the need to address workplace demographics. The increase in Customer Service is primarily due to new hires as part of the implementation of the Conservation Plan. The increase in Operations is primarily due to the hiring of new Apprentice Powerline Technicians and an Electrical Maintenance Apprentice in order to address workplace demographics, primarily due to the aging workforce and to ensure continuity in this skilled trade.

The Company noted that the average current workforce age is 47.6 years and approximately 46% of the workforce is 50 years of age or older. The number of Apprentice Powerline Technicians is forecast to increase from 11 to 26 from 2007 to 2010, which would represent 17% of the total Powerline Technicians by 2010. According to the Company, apprentice employment at this level is necessary to ensure continuity in this skilled trade. Furthermore, the forecast 2010 FTEs has also increased in comparison to 2009 for new employees that will work a partial year in 2009 but are anticipated to be included in the workforce for a full year in 2010.

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 2007 to forecast 2009 and 2010 are included in the table below:

	Salary Cost Per FTE			
			Forecast	
(000's)	**2007**	**2008**	**2009**	**2010**
Salary costs	$ 45,925	$ 47,791	$ 50,309	$ 52,885
Benefit costs (net)	(5,932)	(6,104)	(6,207)	(6,455)
Adjustment relating to clearance accounts	207	77	-	-
Other adjustments	(455)	(639)	(539)	(546)
Base salary costs	39,745	41,125	43,563	45,884
Less: executive compensation	(1,622)	(1,664)	(1,694)	(1,745)
Base salary costs (excluding executive)	$ 38,123	$ 39,461	$ 41,869	$ 44,139
FTE's (including executive members)	627.3	628.2	640.5	650.7
FTE's (excluding executive members)	622.3	623.2	635.5	645.7
Average salary per FTE	**$ 63,358**	**$ 65,464**	**$ 68,014**	**$ 70,515**
% increase		**3.32%**	**3.90%**	**3.68%**
Average salary per FTE (excluding executive members)	**$ 61,261**	**$ 63,320**	**$ 65,884**	**$ 68,358**
% increase		**3.36%**	**4.05%**	**3.76%**

The increasing average salary per FTE in 2009 and 2010 is primarily related to wage increases based on collective agreements for unionized employees and annual increases for managerial and executive salaries.

An analysis of salaries and wages by type of labour and by function within the Company is as follows:

	(000's)		(000's)	
			Forecast	
	2007	**2008**	**2009**	**2010**
Type				
Internal Labour	$ 45,925	$ 47,791	$ 50,309	$ 52,885
Overtime	3,371	3,992	3,571	3,653
	49,296	51,783	53,880	56,538
Contractors	7,654	8,329	8,124	8,464
	$ 56,950	$ 60,112	$ 62,004	$ 65,002
Function				
Operating	$ 28,809	$ 29,013	$ 29,996	$ 31,173
Capital and miscellaneous	28,141	31,099	32,008	33,829
	$ 56,950	$ 60,112	$ 62,004	$ 65,002

Our review of salaries and benefits included an analysis of the year-to-year variance, consideration of the trends in labour costs and discussion of the significant variances with Company officials.

As indicated in the table, internal labour costs forecast for 2010 are 10.6% higher than 2008. According to the Company, the increases in 2009 and 2010 are due to normal salary increases along with the implementation of the Conservation Plan in 2009 and the Apprentice Powerline Technicians program as discussed earlier in the report. Total labour costs are forecast to increase by 8.1%. Overtime for 2008 was higher than 2007 as a result of increase in work associated with customer growth. Overtime is forecast to return to lower levels in 2009 and 2010. The 2009 contractor costs are lower than 2008 due to lower forecast customer connections (4,396 versus 4,625). The 2010 contractor costs are higher than 2009 primarily due to an expected contractor price increase as a result of a contract renewal in 2010 partially offset by a reduction in customer connections over 2009 (3,864 versus 4,396). The capital and miscellaneous labour for 2008 was higher than 2007 due to more customer related capital work. Capital and miscellaneous labour forecast for 2010 is 8.8% higher than 2008 due to inflationary increases and expected increases in contractor costs as a result of a contract renewal for 2010, as previously noted.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2007 and 2008 and the targets set for 2009 for corporate measures under the STI program:

Measure	2007 Actual	2008 Actual	2009 Target
Controllable Operating Costs / Customer	$206	$206	$206
Earnings	$29.9 m	$32.3 m	$31.7m
Outage Hours/Customer (SAIDI)	-	2.7	2.74
Outage/Customer (SAIFI)	2.1	-	-
Customer Satisfaction	88%	89%	89%
All Injury/Illness Frequency Rate	2.0	2.7	2.2
Customer Satisfaction - 1st Call Resolution	87%	88%	88%

In 2008 and 2007 the Company changed some of the measures used in the STI program. In 2007, the STI measure 'Reliability – Duration of Outages' (SAIDI) was replaced with '1st Call Resolution'. In 2008, the measure 'Reliability – Outages per customer' (SAIFI) was replaced with the SAIDI measure. The 2009 measures remain the same as 2008. According to the Company, 2010 targets will not be approved by the Board of Directors until January 2010.

Another aspect of the Company STI plan that is used to determine the percentage payout is the individual performance measure. This measure is used to increase the accountability and achievement of individual performance targets. The weight between corporate performance and individual performance differs between the managerial classifications, as outlined in the following table.

Classification	Corporate Performance	Individual Performance
President and CEO	**75%**	**25%**
Other executives	**60%**	**40%**
Managers	**50%**	**50%**

The individual measures of performance are developed in consultation with the individuals and their respective executive members. Performance measures for the President and the executive members 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 2009 and 2010 is established as a percentage of base pay for the three employee groups. The 2009 and 2010 forecasts for incentive pay are based on a payout of 100% of targets as there is no substantive evidence to indicate that a number higher than 100% will be achieved in either of these years.

The following table illustrates the target as a percentage of base pay. The comparative information for 2007 and 2008 reflects targets and actual payouts for those years.

STI Payout

	Target 2010	Target 2009	Actual 2008	Target 2008	Actual 2007	Target 2007
President	N/A	40%	48%	40%	54%	40%
Vice Presidents	N/A	30%	37%	30%	41%	30%
Managers	N/A	15%	18%	15%	19%	15%

In dollar terms the STI payouts forecast for 2009 and 2010 compared to 2007 and 2008 are as follows:

	Actual		Forecast	
	2007	**2008**	**2009**	**2010**
Executive	$500,000	$478,000	$419,000	$432,000
Managers	208,700	210,200	188,000	193,000
Total	$708,700	$688,200	$607,000	$625,000

Any payout over 100% of the Target is deemed to be a non-regulated expense.

Company Pension Plan

For 2009 and 2010, we analyzed the estimates supporting the forecast gross charge for pension expense of $2,577,000, and $5,701,000 respectively. The 2009 expense is forecast to be $462,633 lower than the 2008 actual of $3,039,633 and 2010 is forecast to increase by $3,124,000 from the 2009 estimate.

The components of pension expense are as follows:

	(Note 1)		Forecast	
	2007	**2008**	**2009**	**2010**
Pension expense per actuary	$ 4,372,342	$1,883,316	$1,339,000	$4,424,000
Pension uniformity plan/SERP	486,884	413,650	453,000	459,000
Group and Individual RRSPs	743,639	790,667	825,000	858,000
Less: Refunds	(36,324)	(48,000)	(40,000)	(40,000)
Total Pension Expense	$ 5,566,541	$ 3,039,633	$ 2,577,000	$ 5,701,000

Note 1: Total pension costs for 2007 on Exhibit 2 include $134,000 relating to the amortization of retiring allowance of the 2005 early retirement program. Retiring allowances are discussed further in our report.

Overall, pension expense for 2008 is lower than 2007 primarily due to the amortization of higher returns on pension plan assets experienced in the previous year, and a higher discount rate determined at December 31, 2007 associated with the Company's accrued benefit obligation. Under Canadian GAAP pension accounting rules the differences between expected results and actual results are shown as actuarial gains/losses and are amortized over the expected average remaining service life of active employees. As such, material differences in certain assumptions (such as the rate of return on plan assets) are not reflected in the current year's expense.

The principal reason for the increase in pension expense in 2010 compared to 2009 and 2008 is due to the amortization of the $41 million loss in asset value experienced in 2008 in the Company's defined benefit pension plan. A discussed in the Company's 2008 annual report, the expected long term rate of return on pension assets was 7.5% for 2008 but the actual rate of return was a loss of (16.6)%. The 2008 loss in asset value is not fully reflected in 2009 pension expense due to the Company's use of the market-related method of valuing pension assets for purposes of determining pension expenses. The 2009 pension costs are forecast to decrease in comparison to 2008 principally due to a 2% increase in the discount rate used to value defined benefit pension obligation. The actual and forecast pension expense included in the table above is consistent with calculations provided by the Company's actuary.

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 and prudent and properly chargeable to the operating account of the Company.

As a result of the closure of the Defined Benefit Pension Plan, all new employees are required to participate in the Defined Contribution Plan (Individual RRSPs). The employer's portion of the contributions to the Group RRSP is calculated as 1.5% of the base salary paid to the plan participants. Individual RRSPs will increase year over year with the number of new hires at the Company. Group and Individual RRSPs are forecast by the Company using an estimated salary escalation factor of approximately 4% for 2009 and 2010.

Retiring Allowance

The retiring allowance costs from 2007 to 2008 and forecast 2009 and 2010 are as follows:

			Forecast	
(000)'s	**2007**	**2008**	**2009**	**2010**
Early Retirement Program	$ 134	$ -	$ -	$ -
Terminations and Severance	24	68	45	45
Normal Retirements	182	236	235	275
Other Retiring Allowance Costs	6	4	5	5
Total	$ 346	$ 308	$ 285	$ 325

The Early Retirement Program expense relates to the amortization of retiring allowance of the 2005 early retirement program approved in P.U. 49 (2004). The final three months of amortization was recognized in 2007. Retiring allowance costs related to the Early Retirement Program are expensed under the "Pension costs" line of Exhibit 2 while the remainder of the retiring allowances shown above is expensed under Retirement Allowances. The Company has not planned to offer employees any similar programs in 2009 or 2010. Therefore, it has only forecast for normal retirements to occur during the forecast period.

Intercompany Charges

Our review of Intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003) and P.U 32 (2007);
- compared charges for 2009 and 2010 forecasts to previous years and obtained explanations for unusual fluctuations and trends.

The following table provides a breakdown of inter-corporate charges to affiliates from 2006 to 2008, including forecast charges for 2009 and 2010:

Inter-Corporate Charges to Affiliates

				Forecast	
	2006	**2007**	**2008**	**2009**	**2010**
Printing & Stationary	$ 6,187	$ 5,066	$ 1,216	$ 4,156	$ 3,479
Postage	17,683	20,273	19,907	19,288	19,823
Staff Charges	1,019,501	894,468	1,057,284	990,418	980,723
Staff Charges - Insurance	143,748	201,731	229,330	191,603	207,555
IS Charges	30,353	27,251	31,192	29,599	29,347
Pole Installations	60,134	24,911	19,295	34,780	26,329
Miscellaneous	43,857	70,197	154,799	89,618	104,871
Total	$ 1,321,463	$ 1,243,897	$ 1,513,023	$ 1,359,462	$ 1,372,127

The forecast for 2009 is based on a three year average from 2006 to 2008. The forecast for 2010 is based on three year average from 2007 to 2009F. By taking the 3 year average, the Company has not properly factored in the change in methodology for determining charge out rates for insurance effective April 1, 2008.

The most significant observations from our analysis of charges to affiliated companies from 2006 to 2008 are as follows:

- Staff charges in 2006 were high primarily due to retirement costs of $264,000 paid to an employee who had been seconded to Belize Electricity. The increase in staff charges in 2008 was primarily the result of Newfoundland Power employees being part of the Hurricane Relief group that helped restore electricity to the Turks and Caicos Islands after Hurricane Hannah and Ike caused extensive damage and power outages in September 2008.

- Staff charges – insurance for 2007 increased over 2006 due to more work being performed for Fortis Inc. ($46,682), Caribbean Utilities Company Ltd. ($15,483), Turks and Caicos ($9,402) and the addition of Terasen Inc. ($3,911). 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.

- The increase in miscellaneous in 2008 is primarily related to the hurricane relief effort in Turks and Caicos as explained above.

The following table provides a breakdown of regulated inter-corporate charges from affiliates from 2006 through 2008, including forecast charges for 2009 and 2010:

Regulated charges from affiliates	**2006**	**2007**	**2008**	**2009** (Forecast)	**2010** (Forecast)
Trustee fees	$ 73,396	$ 87,322	$ 34,000	$ 36,000	$ 38,000
Listing and filing fees	16,927	17,748	-	-	-
Miscellaneous	881,976	146,177	177,920	163,000	163,000
Hotel/Banquet facilities & meals	20,312	38,797	52,171	45,000	45,000
Staff charges	21,880	-	-	-	-
	$ 1,014,491	$ 290,044	$ 264,091	$ 244,000	$ 246,000

The most significant observation from our analysis of charges from related companies is that miscellaneous expenses decreased by $735,799 from 2006 to 2007. This is related to the transfer of 381 poles purchased from Fortis Inc. for the Howley cabin area costing $513,631 as noted in the 2006 annual review. Also, meter refurbishments were awarded to a non-affiliated supplier in early 2007 eliminating this expense from miscellaneous charges from affiliates. The forecast 2009 and 2010 regulated charges from affiliates are fairly consistent with 2007 and 2008.

Beginning in 2008, Fortis Inc. changed its process for the quarterly billing of recoverable expenses. It now bills 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.

As part of the 2008 annual review we reviewed Fortis Inc.'s methodology to estimate its recoverable expenses over the first three quarters as well as its true up calculation for 4th quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets but there were noteworthy changes to the methodology adopted for 2008 as well as the pool of costs being recovered. We noted the following:

- For 2008, Fortis Inc. estimated its net pool of operating expenses in Q4 2007 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.
- Up to and including 2007, no staffing related charges were recovered from the subsidiaries by Fortis Inc. Effective January 1, 2008, certain staffing and staffing related charges, as well as certain consulting and legal fees, were included in the pool of recoverable expenses. Of these expenses, Fortis deemed 50% of the CEO's and CFO's salary and related costs to be borne by Fortis Inc. for business development and consequently is excluded from the pool of recoverable expenses. Additionally, certain consulting and legal fees that are attributable to business acquisition activity are excluded.
- The model includes a 'phase in' adjustment for allocating the recoverable expenses with 100% being recoverable by 2010. This was meant to lessen the impact on the existing subsidiaries. For 2008, there was an 85% 'phase in' adjustment applied and 87.5% is expected for 2009.
- The recoverable costs are net costs as 'other income' from Fortis Inc. is used to reduce the pool of expenses so that only the net recoverable costs are billed out on a pro-rata basis to subsidiaries.
- Due to year end reporting time constraints, Fortis Inc. used actual year-to-date expenditures up to November and estimated December's expenses for the determination of its actual 'true up' calculation. Fortis also used actual assets at October 31, 2008 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of December's expenditures had a minimal impact. We also re-calculated the allocations based on December 31, 2008 actual assets

and noted that the allocated recoveries to the Company related to regulated operations was not significant with a difference of less than $1,000.

Interest and Finance Charges

The following table summarizes the various components of finance charges:

(000's)	Actual 2007	Actual 2008	Forecast 2009	Proposed 2010
Interest				
Long-term debt	$ 33,718	$ 32,334	$ 34,604	$ 35,849
Other	1,525	1,494	419	355
Amortization				
Debt discount	256	235	222	187
Capital stock issue	62	62	38	38
Interest charged to construction	(622)	(618)	(366)	(405)
Interest earned *	(1,477)	-	-	-
Total finance charges	$ 33,462	$ 33,507	$ 34,917	$ 36,024

* Beginning in 2008, the Company has reclassified interest earned and interest on overdue accounts as other revenue for financial statement reporting purposes.

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 total finance charges were analyzed as a percentage of average debt which is forecast to remain relatively stable over 2009 and 2010. The average cost of debt for 2008 was 7.57% compared with 7.69% in 2009 and 7.63% in 2010. This increase from 2008 is primarily due to the May 2009 6.61% first mortgage bond issue which refinanced the existing short-term debt that had an approximate average rate for 2008 of 3.8%. The bond issue was for $65 million with a term of 30 years which, according to the Company in CA-NP-26, is representative of the average life of the assets being financed.

The long-term debt interest in 2009 and 2010 is forecast to increase primarily due to the Company's May 2009 bond issue as discussed above.

Other interest which includes interest on short term debt is forecast to decrease significantly for 2009 and 2010 in comparison to 2008. In 2008 other interest included $258,000 in interest from a short term loan with an interest rate of 3.15% provided to the Company in May 2008 by Fortis Inc. which was repaid in the third quarter of 2008. The decrease in other interest reflects both lower average interest rates on the Company's credit and demand facilities and lower forecast average short term debt in 2009 and 2010. The average short term borrowing rate is forecast to be 1.4% for 2009 and 2.0% for 2010 compared to 3.8% for 2008. As discussed above, the May 2009 bond issue replaced the Company's short term borrowings which at December 31, 2008 was $32 million. We have reviewed the short term interest rates included in the Company's assumptions and they appear reasonable.

Purchased Power

We have reviewed the Company's purchased power expense forecast for 2009 and 2010 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided.

The overall total forecast purchased power expense for 2009 has increased by $9,508,000 over the 2008 actual, which represents a 2.82% increase. On a unit cost level, the increase from $0.06617 cost per kWh in 2008 to $0.06667 per kWh in 2009 represents a 0.75% increase. The 2010 forecast, with proposed changes, shows an increase of an additional $5,776,000 due to increased sales and an increase in unit cost of approximately 0.66% from 2009 to $0.06711 per kWh.

In addition to the increasing cost per kWh noted above, the Company is also forecasting a 1.8% increase in consumption in both residential and commercial markets due to general economic growth in 2009 and a continuing high proportion of electric heating in new home construction. In 2010, consumption is forecast to increase by an additional 1%.

Based upon our analysis, purchased power forecast for 2010 appears consistent with changes in the mil rate and forecast increases in energy sales.

Income Tax Expense

Our review of income tax expense included a recalculation of income taxes based on substantively enacted corporate income tax rates for Federal and Provincial jurisdictions and an assessment of reasonableness based on forecast income and substantively enacted rates for 2009 and 2010.

The amount of income tax expense incurred by the Company over the last two years, and as forecast, is as follows:

Income Taxes	**Actual**		**Forecast**		**Proposed**
	2007	**2008**	**2009**	**2010**	**2010**
Income taxes (000s)	12,668	19,677	16,683	13,132	21,167
Effective income tax rate (%)	28.6%	36.8%	32.8%	32.6%	32.8%
Statutory income tax rate (%)	36.1%	33.5%	33.0%	32.0%	32.0%

The income tax figure presented above excludes the effect of non-regulated operating costs.

Newfoundland Power's effective income tax rate increased from 2007 to 2008 principally due to tax effects associated with regulatory amortizations and cost deferrals, and the adoption of the accrual method of accounting for income tax related to pension costs which commenced in 2008.

The Company's effective income tax rate is forecast to decrease in 2009 and 2010 in comparison to 2008 due to reductions in the statutory corporate income tax rate and the fact that the Company paid the final instalment of $2.5 million in 2008 which related to the 2005 income tax settlement.

Proposed 2010 income tax expense has increased by $8.0 million in comparison to the existing 2010 income tax expense. This is a result of forecast increase in revenues from rates and a decrease in tax deductible expenses. The effective income tax rate has remained relatively consistent with the 2010 existing forecast.

Based upon our analysis, income tax expense for forecast 2009 and proposed 2010 appear consistent with changes in the substantively enacted corporate income tax rates and forecast increases in net income.

Non-Regulated Expenses

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

- assessed the Company's compliance with P.U. 32 (2007); and
- compared non-regulated expenses for the 2009 and 2010 forecast to prior years and investigated any unusual fluctuations:

Non-regulated expenses	**Actual**		**Forecast**	
	2007	**2008**	**2009**	**2010**
Recoverable charges billed by Fortis	$ 418,000	$ 551,000	$ 740,000	$ 869,000
Labour - regular and standby	547,600	558,600	395,000	424,000
Non-regulated expenses - general	130,500	106,800	150,000	150,000
Corporate donations and Advertising	267,400	367,600	270,000	270,000
Non-regulated expenses before tax	1,363,500	1,584,000	1,555,000	1,713,000
Less: Income taxes	492,500	530,600	513,000	548,000
Less: Part V1.1 tax adjustment	760,100	58,200	-	-
Non-regulated expenses after tax	$ 110,900	$ 995,200	$ 1,042,000	$ 1,165,000

The 2010 non-regulated expenses have been forecast at $1,713,000 (before tax) as compared to $1,584,000 in 2008.

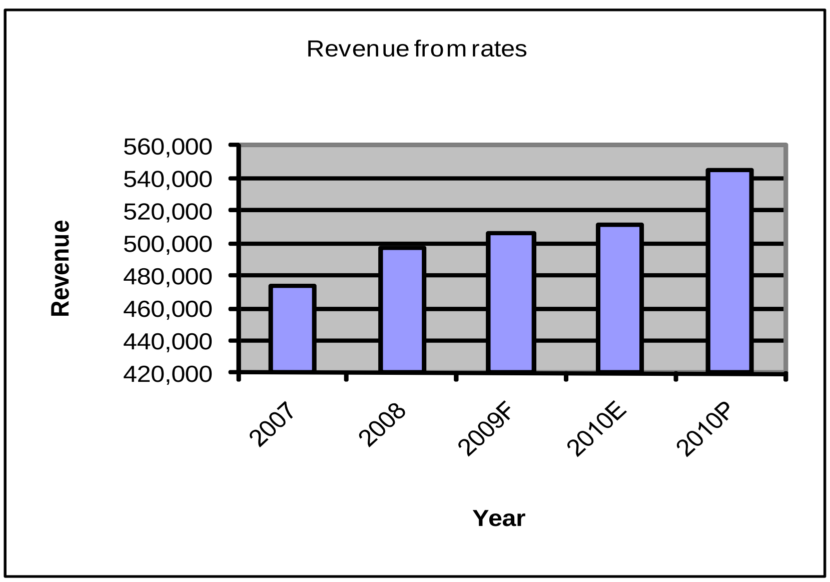
Regular and standby labour costs include STI payments above the 100% performance level and executive stock option expenses. In 2008 actual STI payments were based on performance levels of 137%. For forecast purposes, STI payments are assumed to be at the 100% performance level. The increase in forecast recoverable charges from Fortis Inc. is due to the phase in of recoverable costs from subsidiaries, which began in 2008. The phase in allocation for 2008 actual was 85%, with an expected phase in allocation of 87.5% and 100% for 2009 and 2010, respectively, as explained earlier in our 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, including P.U. 32 (2007).

Proposed Forecast Revenue

We have compared the actual revenues for 2007 to 2008 to the forecast revenues as proposed by the Company for 2009 to 2010 to assess any significant trends. The Company has indicated in its Application that the revenue forecast is based on the customers, energy and demand forecast dated May 2009. The results of this analysis of revenue by rate class are as follows:

				Existing	Proposed
	Actual		Forecast		
(000's)	2007	2008	2009	2010	2010
Residential	$ 284,113	$ 302,916	$ 309,348	$ 315,855	$ 335,672
General Service					
0-10 kw	12,043	11,742	11,809	11,864	12,377
10-100 kw	62,237	63,129	63,844	64,969	67,823
110-1000 kva	70,946	72,997	74,303	75,133	79,364
Over 1000 kva	29,880	31,208	31,354	31,325	33,409
Streetlighting	12,214	12,722	12,844	12,949	13,804
Discounts forfeited	2,621	2,646	2,782	2,722	2,863
Forecast operation of the Formula				(3,192)	
Revenue from rates	474,054	497,360	506,284	511,625	545,312
		4.92%	1.79%	1.05%	7.71%



The following is a summary of the rate changes approved by the Board from 2007 to 2009 and the Company's request for 2010 (all rates provided here exclude adjustments relating to Rate Stabilization Adjustment or the Municipal Tax Adjustment):

- 2007 – 13.88% net increase effective January 1, 2007
- 2008 – 2.89% increase effective January 1, 2008
- 2008 – 0.18% decrease effective July 1, 2008
- 2010 – 6.1% proposed increase effective January 1, 2010 as a result of this 2010 general rate application.

According to the table on the previous page, the Company's revenues have been increasing by various percentages since 2007. The Company has noted the following reasons for the changes in the revenue levels from 2007 to 2008.

- The 4.9% increase in 2008 over 2007 was primarily due to customer and sales growth along with the rate increase of January 1, 2008 as a result of the 2008 GRA for Newfoundland Power offset partially by the decrease beginning July 1, 2008 as a result of the 2009 income tax true-up for Newfoundland Power.

- The 2009 forecast increase in revenue of 1.8% over 2008 is a result of customer and sales growth.

- The 2010 forecast increase in revenues using existing rates in effect as of July 1, 2008 is 1.7% over the 2009 forecast, before the Company's forecast operation of the Formula, which is a combination of customer and sales growth. Under the new rates proposed in this Application the increase in revenues for 2010 is forecast at 7.7%, which is a combination of customer and sales growth and the proposed rate increase of 6.1%.

The number of customers and the GWh's sold to these customers for 2007 to 2008 and forecast 2009 and proposed 2010 are as follows:

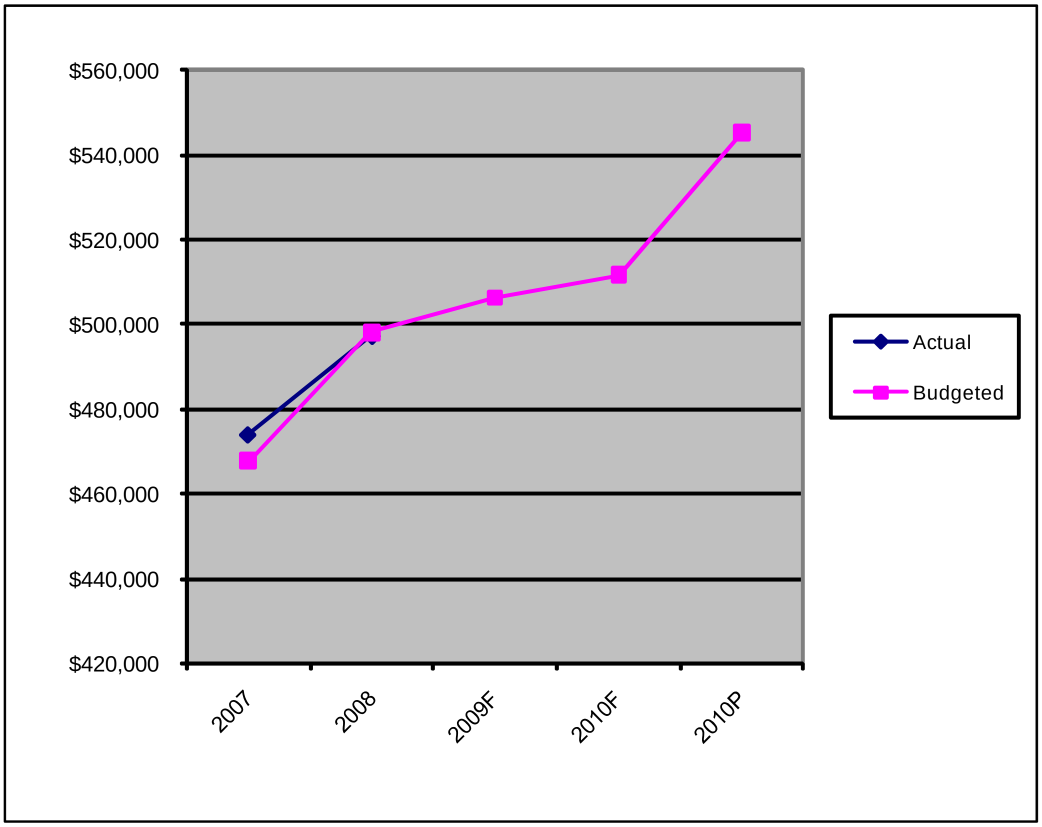
	Actual		Forecast		
				Existing	Proposed
	2007	2008	2009	2010	2010P
Customers	232,262	235,778	238,901	241,431	241,431
% Change	1.20%	1.51%	1.32%	1.06%	1.06%
GWh Sold	5,093	5,208	5,303	5,396	5,355
% Change	1.96%	2.26%	1.82%	1.75%	0.98%

As the above table indicates, from the beginning of 2007 to 2008 the number of customers increased at an average annual rate of 1.36%. This trend is forecast to continue for 2009 and 2010 forecast with an annual rate increase of 1.32% and 1.06%, respectively. GWhs sold has increased at an average annual rate of 2.11% from the beginning of 2007 to 2008. The Company has forecast growth in GWhs sold of 1.8% and 1.7% for 2009 and 2010 existing, respectively. The decrease of 41 GWhs sold from existing and proposed 2010 forecast is related to the elasticity effects of the proposed 2010 customer rate increase, with 38 GWhs of this decrease pertaining to the domestic class Rate #1.1.

The following table details the actual versus budgeted revenues from rates for 2007 to 2008, the forecast 2009 and 2010 revenues and the proposed 2010 revenues.

(000's)

	2007	2008	2009F	2010F	2010P
Actual	$474,054	$497,360			
Budgeted	$467,845	$498,226	$506,284	$511,625	$545,312
Over (Under) Budgeted	1.33%	(0.17%)			



In assessing the validity of the 2009 and 2010 forecast revenues, we agreed all forecast amounts to supporting schedules provided by the Company. In addition, we calculated the average revenue forecast per customer by rate class to assess its reasonableness. We also analyzed all revenue items for any significant or unusual variances.

Based on our procedures nothing has come to our attention to indicate the forecast revenues for 2009 and 2010 appear unreasonable.

Other Revenue

The Company's other revenue from 2007 to 2008 and forecast for 2009 and 2010 is as follows:

($000s)	2007	2008	2009F	2010F	2010P
Pole Attachment	$ 8,568	$ 8,861	$ 9,172	$ 9,365	$ 9,365
Amortization of Municipal Tax ("MTA") Liabilitiy	-	1,362	1,362	1,362	1,362
Miscellaneous	1,852	1,889	2,261	1,851	1,723
Customer account interest	1,477	1,155	1,209	1,222	1,222
Total	**$11,897**	**$13,267**	**$14,004**	**$13,800**	**$13,672**

Pole attachment charges are the largest component of other revenue. The forecasts for 2009 and 2010 include continued increases in revenue from pole attachments as compared to 2008. The Company is estimating that the number of joint-use utility poles will increase by 4.1% (196,984 vs. 205,000) from 2007 to 2010.

The amortization of the Municipal Tax Liability relates to the 3 year amortization of the timing difference in the recovery and payment of municipal taxes. This was approved in P.U. 32 (2007) and the amortization concludes in 2010.

According to the Company, miscellaneous includes items such as customer jobbing charges, wheeling charges, fee changes relating to the Company's regulations governing service, and other revenue amounts. The increase in the 2009 forecast is the result of a $384,000 gain on sale of property.

Proposed Revenue from Rates

The Company is proposing that the Board approve rates, tolls and charges effective for service provided on and after January 1, 2010, to provide an average increase by class in electrical rates of 6.1%, based upon:

a) a forecast average rate base for 2010 of $867,396,000;
b) a rate of return on average rate base for 2010 of 9.15% in the range of 8.97% to 9.33%; and
c) a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in paragraphs 13 and 14 of the Application, of $545,312,000 for 2010.

We have reviewed the Company's proposed rates effective January 1, 2010. Specifically, the procedures we have performed include the following:

1. A recalculation of the revenue that results from using the revised rates, ensuring that it agrees with the revenue requirement submitted by the Company;

2. Agreement of the factors used in the revenue calculations (number of customers, energy and demand usage, etc.) to those presented by the Company;

3. Agreement of the rates used in the revenue calculations to those in the proposed Revised Schedule of Rates, Tolls and Charges; and,

4. A recalculation of the percentage increase in revenue by rate class and the percentage increase in individual rates, tolls and charges.

The following table provides the forecast 2010 revenues by rate class with the proposed increases:

	Existing Rates	Proposed Rates	Change ($)	Change (%)
DOMESTIC - RATE # 1.1				
Basic Customer Charge (Monthly)	$15.56	$15.56	$0.00	0.00%
Energy Charge - All Kilowatt Hours (Cents/kWh)	9.631¢	10.370¢	0.739¢	7.67%
G.S. 0-10 kW - RATE # 2.1				
Basic Customer Charge (Monthly)	$17.85	$17.85	$0.00	0.00%
Energy Charge - All Kilowatt Hours (Cents/kWh)	11.609¢	12.243¢	0.634¢	5.46%
G.S. 10-100 kW - RATE # 2.2				
Basic Customer Charge (Monthly)	$20.55	$20.55	$0.00	0.00%
Energy Charge (Cents/kWh)				
First 150 kWh	9.163¢	9.696¢	0.533¢	5.82%
All Excess kWh	6.863¢	7.251¢	0.388¢	5.65%
G.S. 110-1000 kVA - RATE # 2.3				
Basic Customer Charge (Monthly)	$92.53	$92.53	$0.00	0.00%
Energy Charge (Cents/kWh)				
First 150 kWh (max. 30,000)	9.032¢	9.634¢	0.602¢	6.67%
All Excess kWh	6.714¢	7.147¢	0.433¢	6.45%
G.S. 1000 kVA - RATE # 2.4				
Basic Customer Charge (Monthly)	$185.08	$185.08	$0.00	0.00%
Energy Charge (Cents/kWh)				
First 100 kWh	7.649¢	8.209¢	0.560¢	7.32%
All Excess kWh	6.589¢	7.063¢	0.474¢	7.19%

The proposed overall increase in rates of 6.1% is mainly attributable to a proposed increase in the energy charge component of residential rates of 7.67% which accounts for the greatest usage of electricity.

Based on our procedures, we find that the revenue requirement as proposed by the Company is calculated based upon the revised Schedule of Rates, Tolls and Charges effective January 1, 2010 and the factors proposed in this Application.

System of Accounts

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

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

During our review, we examined the latest changes to the system of accounts which were filed with the Board. On April 1, 2009, 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. As reported in our 2008 annual review, the Company noted that the revisions were largely due to a number of changes arising from P.U. 32 (2007), including the Company's adoption of the asset rate base method. As a result, a number of returns in its annual return were renumbered and reformatted to improve the flow and clarity of information. In addition, revisions were made to the System of Accounts to reflect several changes in relation to current operations. The revisions consisted of the addition of new accounts, the deletion of older accounts that have been replaced by other accounts or are no longer being used, as well as account description changes. No updates were filed with the Board since April 1, 2009.

The above changes represent changes to the system of accounts since the 2008 GRA.

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.

International Financial Reporting Standards

In January 2006 the Canadian Accounting Standards Board ("AcSB"), a committee of the Canadian Institute of Chartered Accountants ("CICA"), announced that commencing with years beginning on or after January 1, 2011 Canadian Generally Accepted Accounting Principles ("GAAP") will be replaced with International Financial Reporting Standards ("IFRS") for Canadian Publicly Accountable Enterprises ("PAEs"). This decision was confirmed most recently on March 12, 2009 in the second omnibus exposure draft on the adoption of IFRS issued by the AcSB. The transition from Canadian GAAP to IFRS is a fundamental change in accounting standards that will impact over 4,500 companies in Canada.

The Company has provided a summary of the current status of the IFRS transition in Volume 1, Section 3 of its Application. The Company has noted that "the preeminent outstanding issue associated with the transition to IFRS is the future accounting treatment of regulatory assets and regulatory liabilities". We agree with this assessment. The recognition of regulatory assets and regulatory liabilities is currently permitted under Canadian GAAP provided certain conditions are met. Prior to 2009 Canadian GAAP explicitly provided guidance for rate regulated entities. This guidance was removed effective January 1, 2009, however Canadian rate regulated entities can rely on US guidance which effectively permits Newfoundland Power to treat its regulatory assets and regulatory liabilities in the same manner.

IFRS currently does not contain separate guidance on the recognition of regulatory assets and regulatory liabilities. The absence of explicit guidance has resulted in considerable doubt on the appropriate treatment of these assets and liabilities after the transition to IFRS.

As noted by the Company, the International Accounting Standards Board ("IASB") has initiated a project on rate-regulated activities. The Company noted in its Application that an exposure draft on this issue is expected in July 2009 with a final standard currently expected to be published in June 2010.

On July 23, 2009 the IASB issued its Exposure Draft on 'Rate Regulated Activities'. In the Exposure draft the IASB noted that it "has developed the proposed IFRS to define regulatory assets and regulatory liabilities, set out criteria for their recognition, specify how they should be measured and require disclosures about their financial effects". It is important to note that the Exposure Draft does not represent a final standard and the proposed guidance contained therein cannot be used for financial reporting until a final standard has been issued. The IASB has invited comments on any aspect of the Exposure Draft and will accept written comments received by November 20, 2009. At this time it is still uncertain as to what the final standard will contain as it is possible for elements of any exposure draft to change considerably when a final standard is issued.

The core principles of the Exposure Draft are as follows:

- recognition of regulatory assets and regulatory liabilities when the conditions for recognition are met (similar to current standards);
- regulatory assets and regulatory liabilities are measured at their expected present value (this concept is not applied currently under Canadian GAAP for regulatory assets and regulatory liabilities);
- regulatory assets are assessed for impairment when the entity concludes that it is not reasonable to assume that it will be able to collect sufficient revenues from its customers to recover its costs (in general impairment tests tend to be more rigorous under IFRS as compared to Canadian GAAP).

In addition to the impact on regulatory assets and regulatory liabilities the transition to IFRS will also likely impact a number of other assets and liabilities. The Company has noted that it has identified and assessed those IFRSs that have the greatest potential impact on the Company's current financial statements. These include the following: IAS 12 – Income Taxes; IAS 16 – Property, Plant and Equipment; IAS 19 - Employee Benefits; IAS 23 – Borrowing Costs; IAS 36 – Impairment of Assets; IAS 37 – Provisions, Contingent Liabilities and Contingent Assets; IAS 38 – Intangible Assets; and IFRS 1 – First Time Adoption of IFRS.

The transition to IFRS in 2011 must be completed on a retroactive basis, with certain explicit exemptions and exceptions either permitted or required. As such, in the Company's 2011 IFRS compliant financial statements, comparatives for 2010 based on IFRS, must also be included. All adjustments required to convert from Canadian GAAP to IFRS must be reflected in the opening balance sheet of 2010 (effectively January 1, 2010). Adjustments must be recognized directly to retained earnings, unless another category of equity is more appropriate.

In P.U. 32 (2007) the Board ordered Newfoundland Power to file its next depreciation study relating to plant in service as of December 31, 2010. As the Company will be required to report Property, Plant and Equipment in accordance with IFRS in its 2010 comparatives included in the 2011 financial statements, it is now proposing to file the next depreciation study relating to plant in service as of December 31, 2009 rather than December 31, 2010.

We conclude that the Company's proposal to file its next depreciation study relating to plant in service as of December 31, 2009 would provide the Company with detailed information on its property, plant and equipment to facilitate the Company's transition to IFRS.

In P.U. 32 (2007), the Board ordered Newfoundland Power to "provide updates as part of it quarterly reports to the Board as to the status of the AcSB's consideration of the transition to IFRS". The Company has complied with this Order. In addition, as noted in the 2008 Annual Financial Review of Newfoundland Power, the Company is working towards meeting the IFRS conversion timelines and appears to have a robust implementation plan in place.

The Company's transition to IFRS represents a fundamental change in financial reporting and therefore we recommend that the Board require Newfoundland Power to provide updates as part of its quarterly reports to the Board as to the status of the Company's transition to IFRS. This update should contain at a minimum the following: key differences noted between Canadian GAAP and IFRS; the anticipated impact on the Company's financial statements related to the differences noted; and the anticipated impact on average rate base, return on average rate base, return on equity and capital structure related to the differences noted, including the impact on January 1, 2010 opening retained earnings due to transitional adjustments.

Newfoundland Power Inc. **Schedule 1**

Comparison of Total Cost of Energy to kWh Sold

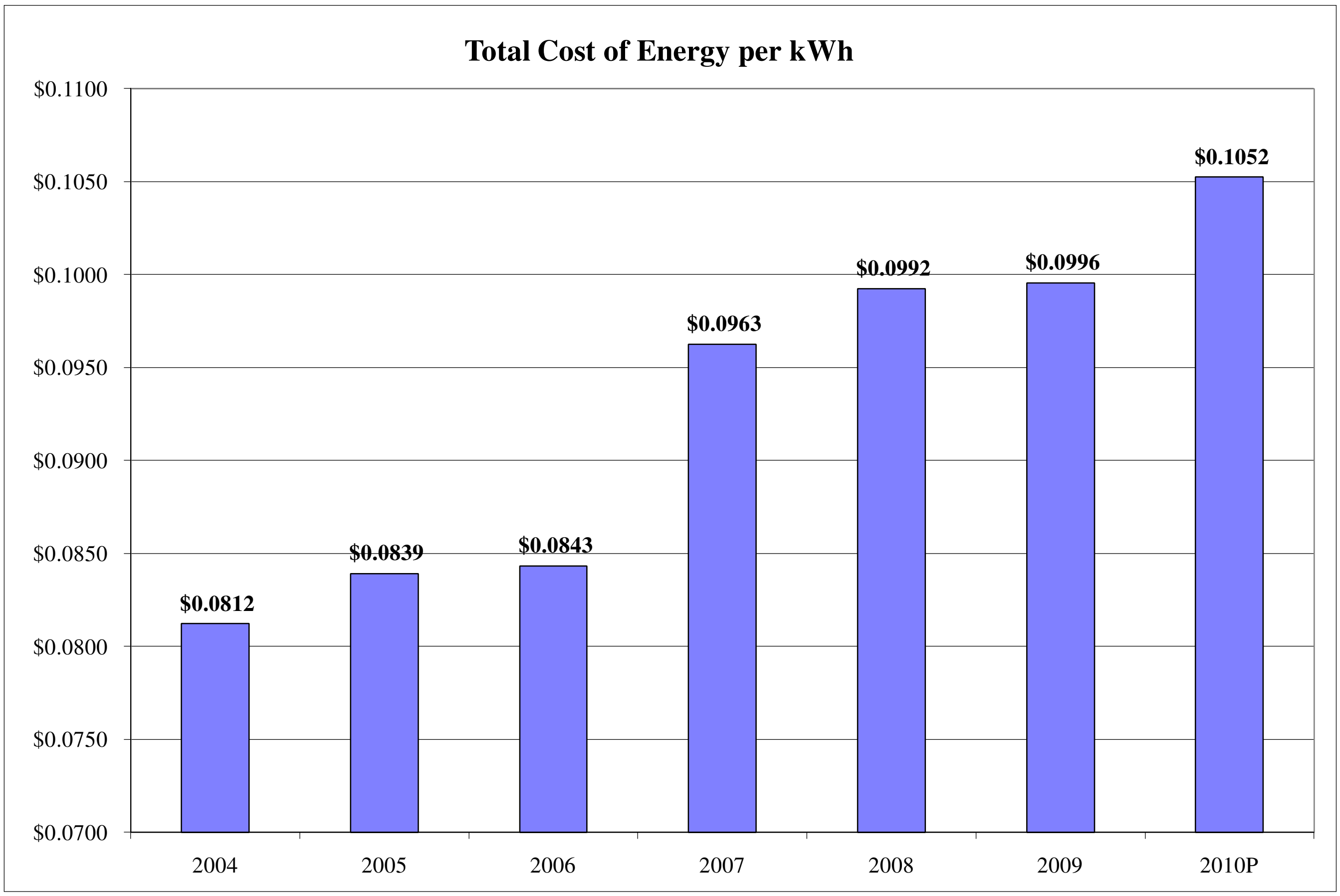
(000)'s

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation	Finance Charges	Income Taxes	Divdends and Return	Total Cost of Energy	Cost per kWh
2004	4,979,000	$ 51,755	$ 244,012	$ 30,987	$ 30,393	$ 15,586	$ 31,714	$ 404,447	$ 0.0812
2005	5,004,000	$ 53,812	$ 255,954	$ 32,143	$ 31,369	$ 15,368	$ 31,317	$ 419,963	$ 0.0839
2006	4,995,000	$ 53,996	$ 257,157	$ 33,129	$ 32,677	$ 13,639	$ 30,666	$ 421,264	$ 0.0843
2007	5,093,000	$ 53,202	$ 326,778	$ 34,162	$ 33,462	$ 12,176	$ 30,452	$ 490,232	$ 0.0963
2008	5,208,000	$ 50,172	$ 336,658	$ 44,511	$ 33,507	$ 19,146	$ 32,895	$ 516,889	$ 0.0992
2009	5,303,000	$ 51,905	$ 346,166	$ 45,715	$ 34,917	$ 16,170	$ 33,064	$ 527,937	$ 0.0996
2010P	5,355,000	$ 65,534	$ 351,942	$ 47,202	$ 36,024	$ 20,618	$ 42,282	$ 563,602	$ 0.1052

* 2006 and 2007 depreciation has been reduced by $5,793,000 related to the deferral of the 2006 True-up. 2008 to 2010 depreciation includes $3,862,000 related to the amortization of the 2006 True-up.

** 2009 operating expenses have been reduced by $1,516,000 for deferral costs related to the Conservation Program

*** Table based on information provided in Exhibit 3 and Exhibit 11 of the Supporting Materials to the GRA



Newfoundland Power Inc.

Comparison of Gross Operating Expenses to kWh Sold

(000's)

		Electricity Supply		Customer Services		General *		Totals	
Year	kWh sold	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh
2004	4,979,000	$ 22,071	$0.0044	$ 9,561	$0.0019	$ 22,162	$0.0045	$ 53,794	$0.0108
2005	5,004,000	$ 21,453	$0.0043	$ 10,136	$0.0020	$ 24,238	$0.0048	$ 55,827	$0.0112
2006	4,995,000	$ 21,194	$0.0042	$ 10,034	$0.0020	$ 24,806	$0.0050	$ 56,034	$0.0112
2007	5,093,000	$ 21,023	$0.0041	$ 10,492	$0.0021	$ 23,653	$0.0046	$ 55,168	$0.0108
2008	5,208,000	$ 20,951	$0.0040	$ 10,436	$0.0020	$ 20,582	$0.0040	$ 51,969	$0.0100
2009	5,303,000	$ 21,525	$0.0041	$ 12,365	$0.0023	$ 19,915	$0.0038	$ 53,805	$0.0101
2010P	5,355,000	$ 22,272	$0.0042	$ 13,050	$0.0024	$ 32,112	$0.0060	$ 67,434	$0.0126

* Includes deferred regulatory costs, deferred CDM costs, pension costs, the impact of accruing OPEBs and early retirement program costs.