Board of Commissioners of Public Utilities
Financial Consultants Report
Newfoundland Power Inc.
2008 General Rate Application Hearing

July 27, 2007

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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 in connection with its 2008 General Rate Application.

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 2008 General Rate Application:

- Review the calculation of depreciation expense and review the updated Depreciation Study, including the proposed amortization of the accumulated reserve variance identified in the study.
- Review the proposed accounting changes with respect to the proposal to use the accrual method of accounting for other employee future benefits, including the related income tax.
- Review the proposed changes to the automatic adjustment formula (AAF), including:
    - proposal to revise the method for determining the risk free rate for the period subsequent to 2008; and
    - proposal to reflect the adoption of the asset rate base method.
- Review proposed treatment of various deferral accounts from January 1, 2008.
- Review the proposal to discontinue the Purchased Price Unit Cost Variance Reserve Account and approve a Demand Management Incentive Account.

Review of 2007 and 2008 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 return on common equity for the years ended December 31, 2002 to 2006, and forecasts for December 31, 2007 and 2008.
- 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, 2007 and 2008 are reasonable and appropriate.
- Review the Company's calculation of estimated average rate base for the year ending December 31, 2008.
- Verify the Company's calculation of the proposed rate of return on rate base and return on common equity for the year ending December 31, 2008.
- Conduct an examination of operating expenses, depreciation and finance charges 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 2008 test year.
- Conduct an examination of rates charged to customers to determine the impact on revenue requirement.

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 year ended December 31, 2002 was audited by Deloitte & Touche, Chartered Accountants. The years ended December 31, 2003 – 2006 have been audited by Ernst & Young, Chartered Accountants. Both 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.

Proposed Accounting Treatments and Policies

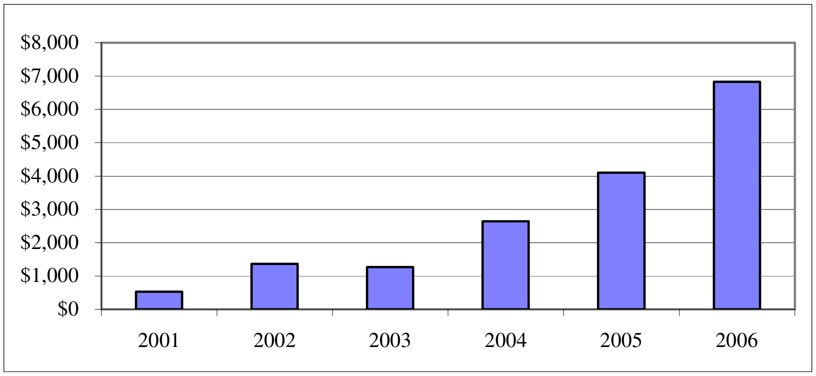
Weather Normalization Reserve

The Weather Normalization Reserve is a combination of two reserves: Degree Day Normalization Reserve and Hydro Production Equalization Reserve. The Degree Day Normalization Reserve normalizes the Company's purchased power expense for annual variations in weather conditions. The Hydro Production Equalization Reserve normalizes the Company's purchased power expense for annual variations in normal stream-flows to its hydro plants. The balances in the Weather Normalization Reserve are filed with and approved annually by the Board. As part of the General Rate Application, the Company has provided a review of the Weather Normalization Reserve which is contained in Volume 2: Supporting Materials, Tab 6.

The Company has stated in its pre-filed evidence that it believes there is significant uncertainty as to whether the current $6,827,000 balance owing from customers in the Degree Day Normalization Component will reverse over time. Over the past five years, the balance in this reserve has increased steadily. Changes in this reserve over the period 2002-2006 are set out in the table and graph on the following page. The balance in this component is directly related to warmer than normal weather conditions experienced in the Company's service area over the past five years. Transfers to and from the Degree Day Component are based on the difference between the marginal revenue and marginal purchased power cost. The Company has stated that the relationship of abnormal weather to contribution to/from the Degree Day Component was reversed upon implementation of the flow-through of the January 1, 2007 Hydro rate change. Due to this change, Newfoundland Power's marginal energy supply costs now exceeds marginal revenues (in the past marginal revenues exceeded marginal costs). As a result, the Company believes that it is unlikely that the balance in this Component will reverse because the conditions that would normally result in a reversal will actually increase the reserve. This reserve is not expected to result in a reversal unless weather continues to be warmer than normal over an extended period.

Weather Normalization Reserve - Degree Day Component

Year	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
000's	$530	$1,368	$1,269	$2,649	$4,099	$6,827



Note: Balances have been taken from the Company's annual returns.

The Company is proposing a five year amortization period which will result in annual amortization of $1,365,000 from 2008 to 2012. Based upon evidence presented by JT Browne Consulting, Newfoundland Power's proposal is consistent with the cost of service standard, the principle of intergenerational equity and the principle of rate stability and predictability. JT Browne Consulting has also pointed out that the five year period was chosen because it is consistent with the amortization period that the Board approved for the amortization of the Hydro component in the 2003 GRA as approved under P.U. 19 (2003).

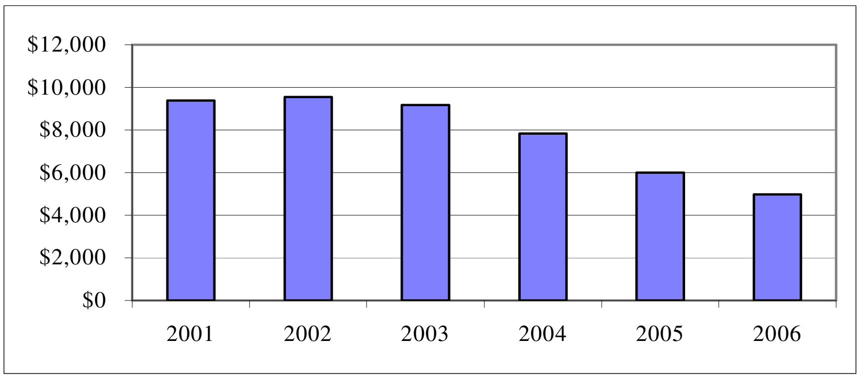
We have reviewed the methodology and historical balances and adjustments for the Degree Day Normalization reserve as well as the evidence put forward by the Company. Based on this review, it appears unlikely that the balance in this reserve account will reverse in the context of the methodology in which this reserve operates. With respect to the proposed amortization period we concur that the five year period is consistent with amortization periods used in past years, in particular, and most relevant, the amortization of the Hydro Component in 2003. A five-year amortization period achieves full recovery within a time frame that minimizes the impact on rates, as compared to a shorter amortization period, such as three years. In terms of impact on revenue requirement, a five-year amortization results in an annual increase of $2,076,000, whereas a three-year period results in an annual increase of $3,460,000 per year.

In P.U. 19 (2003) the Board accepted Newfoundland Power's proposal to amortize the recovery of $5,600,000 in the Hydro Production Equalization Reserve over a five year period from 2003 to 2007. The $5,600,000 represented non-reversing increases in the reserve balance resulting from increases in the purchased power mil rate and income tax. In addition, the Board ordered the Company to review the balance in the Hydro Production Equalization Reserve as of December 31, 2005 and to apply to the Board for an Order as to the disposition of the outstanding balance at the next General Rate Application. The Company has stated in its prefiled evidence that for 2008, no action is required with respect to the existing balance in the Hydro Component. The

Company has noted that the balance in this reserve account has decreased from $9,370,000 in 2001 to $4,981,000 as at December 31, 2006. Changes in this reserve over the period 2002-2006 are set out in the table and graph below.

Weather Normalization Reserve - Hydro Component

Year	2001	2002	2003	2004	2005	2006
000's	$9,370	$9,551	$9,166	$7,828	$6,001	$4,981



Note: Balances have been taken from the Company's annual returns.

We have reviewed the Company's analysis of this balance. The above chart shows that this reserve has been decreasing steadily during the past five years. The major reason for the annual decrease in this reserve is the annual amortization of $1,120,000 resulting from the 2003 GRA. After normalizing for this, the balance in the reserve account has been essentially flat since December 31, 2001. The Board may wish to continue to monitor the reserve balance closely on a normalized basis.

In terms of variations from the normal stream-flows, in 2005 the Company engaged Acres International to update the Water Management Study to incorporate new data available from the preceding five year period. The Water Management Study update is the basis for the normal values used in computing transfers to the Hydro Component since January 1, 2006. The study found that since 2001 the cumulative balance in the Hydro Component has not been materially affected by variances in stream-flows. Actual stream-flows for the five year period from 2002 to 2006 averaged 421.7 GWh, compared to an average normal of 423.2 GWh for the same period.

Overall, we believe the proposed accounting treatments with respect to the weather normalization reserve including the five year amortization of the $6,827,000 non-reversing portion of the Degree Day Normalization Reserve is consistent with past Board practice. We recommend that the Board continue to closely monitor both the Degree Day and Hydro Production Components of the Weather Normalization Reserve as part of its ongoing regulatory supervision to ensure any trends or accumulation of balance are addressed on a timely basis.

Purchased Power Unit Cost Variance Reserve

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland Hydro's proposed demand and energy rate structure. This reserve mechanism is the Purchased Power Unit Cost Variance Reserve used to limit variations in the cost of purchased power associated with the demand and energy rate structure implemented as of January 1, 2005. The net transfer to the reserve for 2006 is $1,342,000 (2005; $Nil) as shown in the table below. The balance represents a regulatory liability as the intention of the reserve was that positive balances would be returned to customers.

Purchased Power Unit Cost Variance Reserve	*(000's)* 2005	2006
Opening balance	$ -	$ -
Unit Cost Variance	(439)	2,779
Deadband	588	714
Variance	-	2,065
Tax Effects	-	(723)
Net Transfer to Reserve	-	1,342
Closing balance	**$ -**	**$ 1,342**

Under P.U. 44 (2004), 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 reserve account. On April 24, 2007, under P.U. 10 (2007), the Board approved Newfoundland Power's proposal to review the treatment of the reserve balance as part of its 2008 GRA.

Newfoundland Power is proposing to amortize this reserve over a five year period which will result in annual amortization of $268,000. Consistent with the amortization of the Weather Normalization Reserve noted above, JT Browne Consulting concluded that the proposed treatment is consistent with generally accepted regulatory principles and is appropriate.

We have reviewed the Company's analysis of this balance, including the proposed amortization. The proposed amortization period will reduce the annual revenue requirement from 2008 to 2012 by $413,000, whereas a three-year period results in an annual decrease of $688,000. The five year period is consistent with the proposed treatment of the other regulatory deferrals and reserve accounts. As an alternative to the five year period, the Board could consider a shorter amortization period as the balance was created over a two year period (since the initial application of the reserve mechanism on January 1, 2005).

In addition to the proposed treatment of the reserve mechanism, the Company is also proposing that a substantially similar mechanism called the Demand Management Incentive, replace the Unit Cost Reserve. The Company is proposing to modify the reserve mechanism to make it explicitly related to demand management. We have reviewed the definition of the Demand Management Incentive Account provided in Exhibit 4 of the Supporting Materials and compared this mechanism to the definition of the Purchased Power Unit Cost Variance Account as provided in P.U. 10 (2007). The key difference in these definitions is that the Purchased Price Unit Cost Variance Reserve is based on a combination of demand and energy costs, as well the variance factor is based on forecasted amounts which are updated each year. The Demand Management Incentive Account is solely based on demand costs and the variance factor is based on the test year. Both reserves require the Company to file an Application with the Board no later than the 1st day of March each year for the disposition of any balance in this account.

We conclude that the proposed amortization of the Purchase Price Unit Cost variance account is consistent with past Board practice for other reserve accounts.

Employee Future 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 includes hospital care, prescription drugs, vision care, other medical, life insurance and retirement allowances. For OPEBs, the Company follows the cash basis of accounting (ie: an expense is recognized when benefits are paid). However, 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 next general rate application, a report which addresses 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 has filed 'A Report on Employee Future Benefits' as part of its' 2008 GRA. Based on this assessment, the Company is proposing what it believes is a measured transition to the Accrual Method which reasonably mitigates the impact on customer rates of the proposed change.

The Company is proposing the following with respect to employee future benefits:

1. adopt the accrual method of accounting for OPEB's costs for regulatory purposes commencing in 2008;
2. tax-effect all of its employee future benefits costs, represented by OPEB's expense and pension expense, for regulatory purposes commencing in 2008; and
3. defer consideration of the transitional obligation of $34,100,000 million until its next general rate proceeding.

These proposals, if approved by the Board, will require a revenue increase of 1.5% in 2008. The following section provides a review of each of these proposals.

Accrual Basis of Accounting

Newfoundland Power proposes to adopt the accrual method of accounting for OPEBs costs for regulatory purposes in 2008. 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 treatments has resulted in a regulatory asset of $27,782,000 recognized on the Company's balance sheet as at December 31, 2006.

The Company has represented that the adoption of the accrual basis for OPEBs will result in an estimated increase in 2008 expenses of $6.4 million (expense under the accrual basis of $7.5 million, less expense under the cash basis of $1.1 million). This change in policy 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. Newfoundland Power is proposing that this liability be deducted from its rate base commencing in 2008 as part of its transition to the asset rate base method (note: the asset rate base method is discussed in greater detail later in our report).

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, 18 out of 26 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)).

In an analysis prepared by JT Browne Consulting, additional support is provided for the adoption of the accrual method. In his report, JT Browne concludes that the adoption of the accrual basis in recognizing OPEBs for regulatory purposes is consistent with the cost of service standard since it will allow the Company to recover its costs of providing service. As well JT Browne stated that the change from the cash to the accrual basis results in a better matching of costs to the periods in which the services are provided (which is consistent with the principle of intergenerational equity).

Based upon our review of this issue, we believe that the Company's proposal of using the accrual method for accounting for other future employee benefits is consistent with the Company's treatment of pension costs, both of which are provided similar treatment for financial reporting purposes under Canadian GAAP (CICA 3461). In addition, as noted above, this treatment is consistent with Newfoundland and Labrador Hydro.

Tax Treatment of Employee Future Benefits

For income tax purposes, the Canada Revenue Agency (CRA) only permits a tax deduction for cash payments in respect of employee future benefits. For pension plans, tax deductions are permitted for plan funding and contributions. For OPEBs, tax deductions are permitted for actual benefits paid during a particular year. Newfoundland Power is proposing to adopt the accrual method of accounting for income taxes related to employee future benefits (including pension plans and OPEBs) effective January 1, 2008. Under the accrual method, the timing of recognizing income tax will match the timing that the related expense is incurred under accrual accounting. For example, income tax expense for a particular year is based on the OPEBs expense based on 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 that the cash paid, income tax expense would increase.

The impact on the 2008 test year related to this policy is as follows:

- For OPEBs, the expense under accrual accounting will exceed the cash paid, resulting in a decrease in income tax expense of $2.0 million.
- For pensions, the expense under accrual accounting will be less than the cash paid, resulting in an increase in income tax expense of $0.5 million.
- The overall proforma impact, on the 2008 revenue requirement including the income tax impacts is estimated by Newfoundland Power to be a decrease of $2.2 million.

In the report provided by JT Browne, he points out that the accrual basis for accounting related to income tax on employee future benefits is consistent with:

a) the cost of service standard - the Company is allowed the opportunity to recover only its estimated income tax;
b) the principle of intergenerational equity - tax savings are matched with their associated expense and reduce the new cost in the period that the related service is provided; and
c) the principle of rate stability and predictability - the resulting reduction in current tax expense will help to offset the increase in revenue requirement by adopting the accrual method for recognizing OPEB costs.

In the absence of rate regulation, accrual accounting for income tax is required under Canadian Generally Accepted Accounting Principles (GAAP). Currently, Newfoundland Power recognizes future income tax liabilities solely on temporary differences in capital cost allowance in excess of amortization of capital assets. The Company does not recognize a future income tax asset when amortization for accounting purposes is in excess of the tax deduction permitted for capital cost allowance. However, under the proposed treatment for OPEBs a future tax asset would be recognized which is favourable to ratepayers.

Based on our review, we conclude that recognizing income tax on the accrual basis for employee future benefits (pensions and OPEBs) is in accordance with Canadian GAAP.

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. As discussed in the report prepared by JT Browne Consulting, there are two components of transitional costs related to Newfoundland Power's move to the accrual method of accounting of OPEBs:

1. 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 December 31, 2008 will be $13,713,000. Typically the annual amortization of the transitional obligation is included in a Company's benefits expense for the year. However, as Newfoundland Power has been recording OPEBs on the cash basis for regulatory purposes, this annual amortization has been recorded as part of the regulatory asset. As a result the estimated OPEB regulatory asset at December 31, 2008 will include $11,420,000 in transitional costs amortization.

   The Company is proposing to continue to amortize the remaining $13,713,000 over 9.6 years (original estimated service life at January 1, 2000 of 17.6 years less time period up to December 31, 2007). This annual amortization of $1,428,000 would be included as part of the Company's OPEB expense under the accrual basis of accounting.

2. As at December 31, 2006 the Company had recorded a regulatory asset of $27,782,000 on its' balance sheet related to other employee benefits. The 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, 2006. The Company estimates that this cumulative difference will increase to $34,100,000 as at December 31, 2007. The Company has estimated that the impact of recovering this regulatory asset would be to increase revenue requirement by 1.4% assuming a five year amortization period (this would decrease to 0.7% 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 the Company's next general rate proceeding. 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.

JT Browne Consulting noted in his report to Newfoundland Power that the estimated regulatory asset of $34,100,000 at December 31, 2007 has accumulated over a relatively short time (since January 1, 2000). Under the principle of intergenerational equity, these costs would normally be recovered as quickly as reasonable so that the customers that eventually pay for the costs are the same as those who benefited from the service.

However, given the impact on customer's rates of recovering this asset, JT Browne has concluded that Newfoundland Power's proposal to defer the amortization of its regulatory asset is a practical solution that recognizes the principle of rate stability and predictability.

Regulatory Deferral Accounts

The Company has asked for Board approval for the proposed treatment of the regulatory deferrals (which includes the 2005 unbilled revenue deferral, the municipal tax liability, the depreciation deferral and the replacement energy deferral) and regulatory reserves (which includes the weather normalization reserve and the purchased power unit cost reserve account). In this application, the Company is proposing a 5-year amortization of the regulatory deferrals and reserves. The weather normalization reserve and the purchase power unit cost reserve balances were reviewed earlier in this report. The following sections review the proposed treatment of the deferral accounts.

Deferrals Accounts

The following is a summary of the forecast regulatory revenue and costs deferrals as at December 31, 2007.

	(000's)
Revenue Deferrals	
2005 Unbilled Revenue	$ 16,446
Municipal Tax Liability	4,087
	20,533
Cost Recovery Deferrals	
Depreciation	11,586
Replacement Energy	1,147
	12,733
Net Cost Deferrals	**$ 7,800**

(a) 2005 Unbilled Revenue

In 2006 the Company adopted the accrual method of accounting for revenue recognition which was approved in P.U. 40 (2005). The Company had previously recognized revenue on a billed basis whereby revenue was recognized when customers were billed according to their billing cycle. Under the accrual basis, electricity consumed is estimated at the end of each reporting period and the associated revenue is calculated using the appropriate rates and accrued as of that date. This change in accounting policy resulted in an Unrecognized Unbilled Revenue balance of $23,631,000 as at December 31, 2005. Pursuant to P.U. 40 (2005) and P.U. 39 (2006) the Company was permitted to recognize $3,086,000 and $2,714,000 of the 2005 Unbilled Revenue in 2006 and 2007 respectively to offset the income tax effects arising from the June 2005 tax settlement with CRA. Under the terms of the tax settlement with CRA, the Company was required to recognize the unbilled revenue balance into taxable income over a three year period commencing in 2006. The Board has permitted the Company to recognize revenue in 2006 and 2007 equivalent to the estimated tax payable. In 2008 the Company estimates that it will pay an additional $2,592,000 in income tax related to the final installment due to CRA.

The forecast balance remaining in this regulatory reserve balance as at December 31, 2007 is $16,446,000.

The Company is proposing the following treatment related to the disposition of this deferred account:

- Recognize $2,592,000 of the unbilled revenue balance in 2008 to offset the 2008 tax payable as was done in 2006 and 2007.
- Amortize the remaining balance of $13,854,000 equally over five years commencing in 2008 resulting in annual revenue of $2,771,000 from 2008 to 2012.

(b) Municipal Tax Liability

A net municipal tax liability of approximately $4,087,000 existed as at December 31, 2006 (gross municipal tax liability of $11,328,000 partially offset by a municipal tax asset of $7,239,000). This timing difference represents revenues collected on account of municipal taxes that are being treated as amounts collected from customers to meet future costs.

The Company believes that from the perspective of the Asset Rate Base Method (ARBM), the municipal tax liability is conceptually similar to the 2005 unbilled revenue. As a result of the Company's transition to the ARBM, this liability results in a reduction in the rate base. Consistent with the proposed treatment of the 2005 unbilled revenue reserve, the Company is proposing to amortize the municipal tax liability over five years resulting in annual amortization of $817,400.

(c) Depreciation

In P.U. 19(2003), the Board approved the amortization of the accumulated depreciation reserve variance ("true-up) of $17,379,000 over a three year period from 2003 to 2005. This resulted in an annual amortization of $5,793,000 which was used to offset depreciation expense from 2003 to 2005. As a result of the conclusion of the annual amortization in 2005, the Company incurred additional depreciation expense in 2006 and 2007 of $5,793,000 equal to the amount of the true-up adjustment. Under P.U. 40 (2005) and P.U. 39 (2006) the Board allowed the Company to defer recovery, by use of a deferral account, of the increased depreciation expense for 2006 and 2007 respectively. In P.U. 39 (2006) the Board recognized that Newfoundland Power was completing an updated depreciation study and that the deferred 2006 and 2007 costs would be reviewed and tested by the Board as part of the 2008 General Rate Application. The total balance in this deferral account will be $11,586,000 at December 31, 2007.

The Company is proposing to amortize this deferred cost over a five year period from 2008 to 2012 resulting in annual amortization of $2,317,000.

(d) Replacement Energy

Under P.U. 39 (2006) the Board approved Newfoundland Power's application to defer for 2007, $1,147,000 in after tax costs associated with the refurbishment of the Rattling Brook hydroelectric plant. During the construction period the Company will have to purchase replacement energy to replace the normal production of the Rattling Brook plant while it is out of service.

The Company is proposing to amortize this deferred cost over a five year period from 2008 to 2012 resulting in annual amortization of $229,400.

Analysis

The pro-forma annual impact on revenue requirement including the net tax impact, as represented by the Company, for 2008 to 2012 related to these deferrals is as follows:

	(000's)				
	2008	**2009**	**2010**	**2011**	**2012**
Revenue Deferrals					
2005 Unbilled Revenue	$ (8,188)	$ (4,230)	$ (4,230)	$ (4,230)	$ (4,230)
Municipal Tax Liability	(817)	(817)	(817)	(817)	(817)
Cost Recovery Deferrals					
Depreciation	3,538	3,538	3,538	3,538	3,538
Replacement Energy	359	359	359	359	359
Revenue Requirement Impacts	**$ (5,108)**	**$ (1,150)**	**$ (1,150)**	**$ (1,150)**	**$ (1,150)**

As shown above, the five year amortization of the regulatory deferrals will reduce pro forma revenue requirements by $5,108,000 in the 2008 test year and $1,150,000 from 2009 to 2012. Alternatively, a three year amortization period would reduce the revenue requirement by $5,875,000 in 2008 and $1,917,000 from 2009 to 2010 thus providing a quicker return to ratepayers.

JT Browne's analysis of the regulatory deferrals centered around the following regulatory principles:

- Cost of service standard which requires that a utility be given an opportunity to recover its costs for providing regulated service, including a fair return on its investment devoted to regulated operations;

- Intergenerational equity principle which requires that customers in a given period should pay only the costs necessary to provide them with service in that period. If costs cannot be recovered in the period for which they were incurred, they should be generally recovered as close to the period for which they were incurred as is reasonable; and,

- Rate stability principle which requires that rates should be stable and predictable, at least to the extent possible.

The 2008 proposed amortization of $2,592,000 in unbilled revenue to offset the additional tax expense is consistent with the treatment approved for 2006 and 2007. The five year amortization period proposed by the Company for the remaining deferrals is consistent with past amortization policies including the recovery of the Hydro Production Equalization Reserve approved in the 2003 General Rate Application, the amortization of the change in GEC from full cost accounting to incremental, and the true-up variance from the 1996 Gannet Fleming depreciation study.

Deferred Regulatory Costs

The Company is proposing to amortize over a three-year period, the estimated external hearing costs of $1,250,000. This amortization is forecast for the years of 2008-2010 and will be charged on an equal basis of $417,000 per year.

The deferral of these costs is intended to better match the costs of major proceedings over the period between them. In addition, it smoothes the effect on the Company's cost of service which is advantageous to the customer. This deferral of regulatory costs is consistent with regulatory principles and practices.

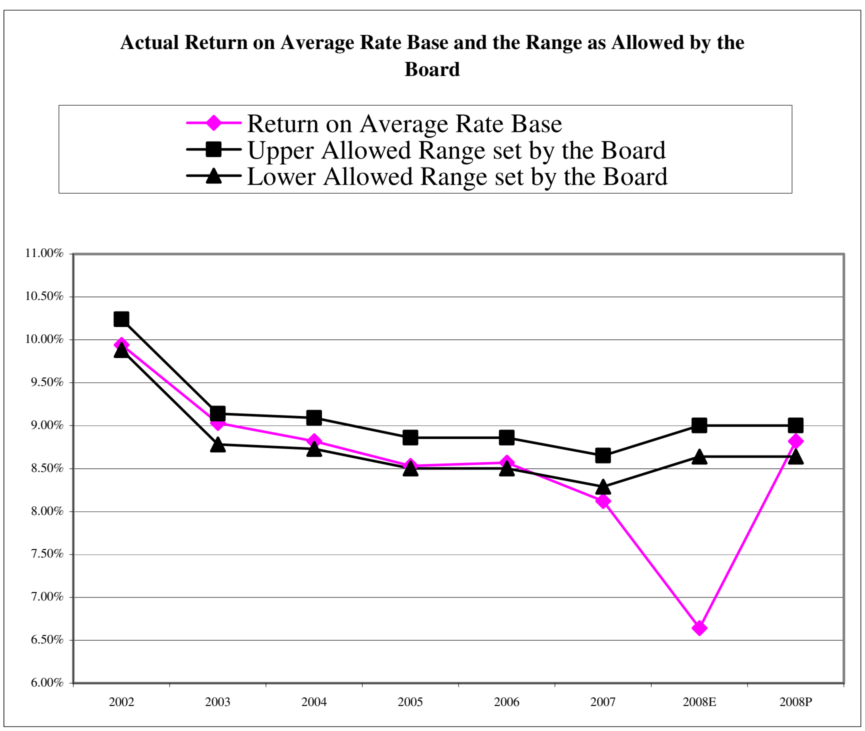
The proposal is consistent with the Board's approval of the deferral of the 2003 external hearing costs. These costs were also amortized over a three-year period commencing in 2003 as approved by the Board in Order No. P.U.19 (2003).

Automatic Adjustment Formula and Asset Rate Base Method

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 rate base and therefore customer rates for 2005 to 2007. This decision also included the move to the Asset Rate Base Method 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 the 2008 Application, the Company is proposing the continued use of the Formula with changes as discussed below in the section called "Company Proposed Changes to the Automatic Adjustment Formula".

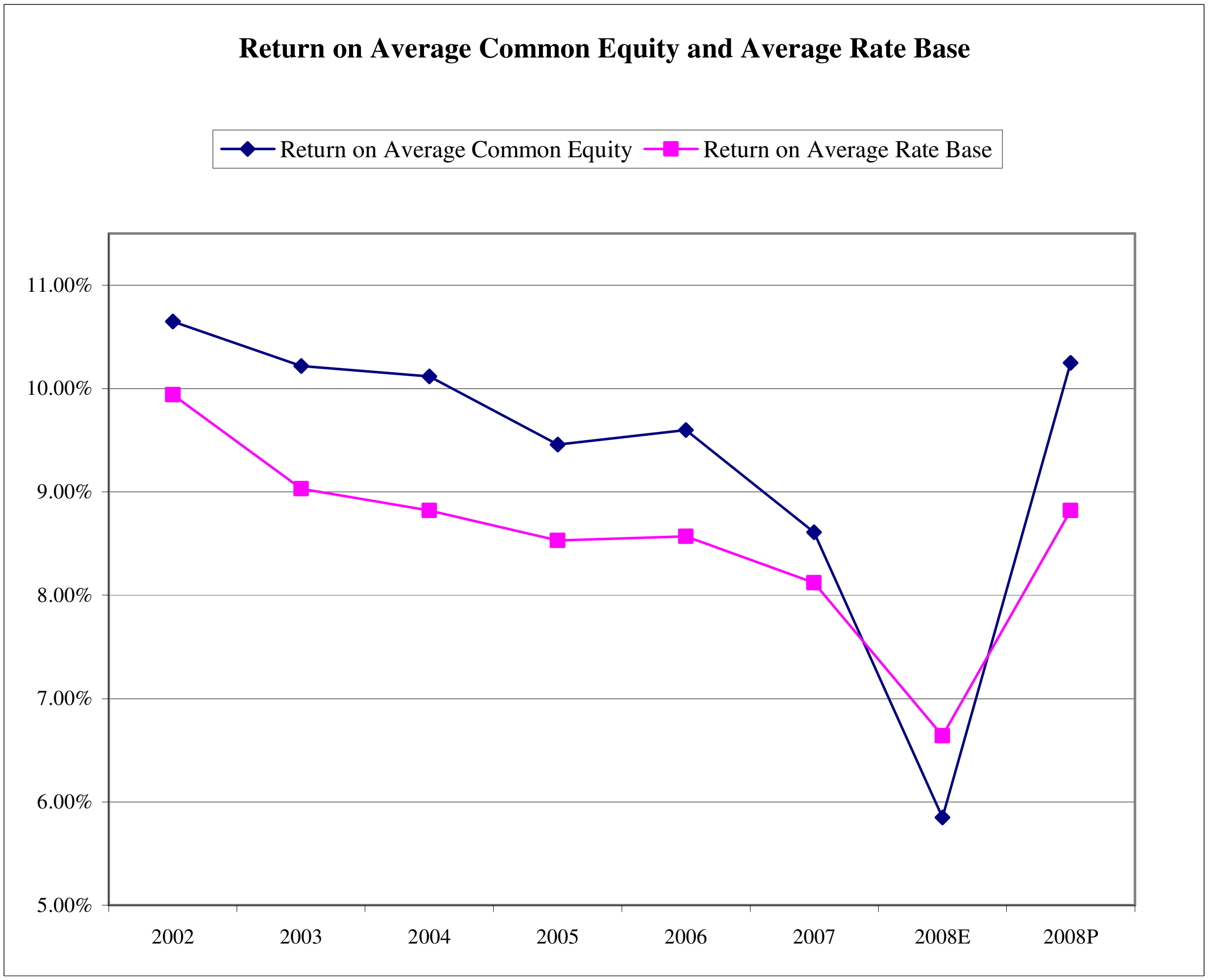
The actual return on rate base in comparison to the range of allowed return for each of the years 2002 to proposed 2008 is set out in the table and graph below. The return on rate base was within the range as set by the Formula for 2002 to 2006. For forecast 2007 and 2008 the return on rate base is below the lower end of the allowed range with the forecast return for 2008 at existing rates of 6.64%. The proposed rate of return for 2008, under the proposed rates, is 8.82% within a range of 8.64% to 9.00%.

	Actual					Forecast		Proposed
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2008**
Return on Average Rate Base	9.94%	9.03%	8.82%	8.53%	8.57%	8.12%	6.64%	8.82%
Upper Allowed Range set by the Board	10.24%	9.14%	9.09%	8.86%	8.86%	8.65%	8.65%	9.00%
Lower Allowed Range set by the Board	9.88%	8.78%	8.73%	8.50%	8.50%	8.29%	8.29%	8.64%



The following is a comparison of the actual return on average common equity up to 2006 and forecast for 2007 and 2008 with the actual return on average rate base for 2002 to forecast 2008.

						Forecast		**Proposed**
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2008**
Return on Average Common Equity	10.65%	10.22%	10.12%	9.46%	9.60%	8.61%	5.85%	10.25%
Return on Average Rate Base	9.94%	9.03%	8.82%	8.53%	8.57%	8.12%	6.64%	8.82%
Spread between actual returns	0.71%	1.19%	1.30%	0.93%	1.03%	0.49%	(0.79%)	1.43%



As demonstrated by the above graph, since 2002 the return on average common equity was higher than the return on average rate base except for the 2008 forecast amount (based on existing rates) which shows a return on rate base of 6.64% versus a return on equity of 5.85%. The proposed 2008 return on rate base would reestablish the normal relationship between the two returns with a higher return on equity of 10.25% versus a return on rate base of 8.82%.

The spread between actual returns on average common equity and returns on average rate base have ranged between 1.30% and 0.71% from 2002 to 2006. The proposed spread between these returns for 2008 is 1.43%.

In P.U. 19 (2003), the Board established a trigger mechanism to monitor the rate of return on common equity and its relationship to return on rate base. Under this mechanism where in a given year the actual rate of return on equity is greater than 50 bps above the cost of equity as determined by the Automatic Adjustment Formula, the Company would be required to file a report explaining the facts and circumstances contributing to the difference. We recommend that this trigger mechanism remain in effect and that the Board continue to monitor this on a go forward basis.

Company Proposed Changes to the Automatic Adjustment Formula

The Company is proposing three changes to the Automatic Adjustment Formula, as follows:

i. that the risk-free rate be 5.00% and the risk premium be set at 5.25%, as recommended by Ms. McShane who prepared a detailed Cost of Capital report. The appropriateness of this proposal will be reviewed by the "cost of capital" experts participating in this hearing.

ii. that changes in the risk-free rate used in the calculation of the weighted average cost of capital ("WACC") be determined by reference to the Consensus Forecasts. In the 2003 general rate application, the Company was proposing to use Consensus Forecasts, however the Board ordered at that time that the Company continue to use the long term Canada Bond Yields.

iii. that the arithmetic expression of the formula be changed to reflect the transition to the Asset Rate Base Method ("ARBM") of calculating rate base. The formula after the transition to the ARBM will be:

    Return on Rate Base = [Rate Base x WACC]

    Through implementing this change there will conceptually be no unreconciled differences between invested capital and rate base in the calculation of the rate of return on rate base. Under the ARBM, the weighted average cost of capital effectively becomes the rate of return on rate base. The "Z" factor differences have all been reconciled to the ARBM as part of this transition.

The Company is proposing the Formula, with these changes, be used to set rates for a further three year period beyond 2008.

Company Proposed Changes to Transition to the Asset Rate Base Method ("ARBM")

Following P.U. 19 (2003) the Company has been implementing Board approved rate base changes that have converted its rate base to the ARBM. Previously, the Company was using average invested capital. Completion of the transition to the ARBM requires that "reconciling items" be addressed. Included in the reconciling items are (1) other assets and liabilities; (2) rate base allowances; and (3) unamortized deferred debt issue costs.

Other Assets and Liabilities

Included in this category are the following items: (i) Customer Finance Programs Receivables (ii) Customer Security Deposits (iii) Accrued Pension Liability (iv) Municipal Tax Liability and (v) Accrued OPEB's Liability.

According to a report on the implementation of the ARBM, differences still exist with respect to these items since the transition was not yet made for these items to the ARBM. These reconciling items will now be eliminated with this proposal. The other assets will be added to the rate base while other liabilities will be subtracted from the rate base. The total impact of this change on the rate base is a decrease of $8,873,000.

Rate Base Allowances

Included in this category are the following items: (i) funds used during construction (AFUDC); (ii) cash working capital; and (iii) materials and supplies.

These items will continue to be components in the calculation of average rate base and the proposals in this Application serve to update these calculations.

The impact of these changes on the rate base is an increase of $2,461,000.

The most significant component of this change is an increase in the cash working capital allowance (CWC) of $2,527,000. The Company's existing CWC allowance of 1.7% was approved by the Board in 1984. The proposed allowance of 2.1% is based on a Lead/Lag study dated May, 2007 and included in the Supporting Materials to this Application. The increased percentage is primarily due to the impact of Harmonized Sales Tax (HST) and the change in the collection pattern of municipal taxes.

Unamortized Deferred Debt Issue Costs

Unamortized deferred debt issues costs are currently included in the Company's rate base, while the amortization of deferred debt issue costs are included in the calculation of the WACC. As both of these items are related to the cost of capital, it would be appropriate that it is included in the calculation of the WACC. As a result, the Company has excluded the unamortized deferred debt issue costs from the rate base.

The impact on the rate base is a reduction of $3,368,000.

The overall impact on the rate base from the above three changes is a reduction of $9,780,000.

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, 2007 and 2008 are included on Exhibit 5 Page 5 of 8 (Volume 1). 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 2007 and 2008;

- recalculated the forecast rate base for 2007 and 2008; and,

- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act to ensure it is in accordance with established policy and procedure and that it appropriately reflects proposed changes to transition to the Asset Rate Base Method.

The following table summarizes the rate base under existing and proposed approaches:

($000's)	Existing	Impact	Proposed
Plant Investment	$ 1,252,345	$ (47)	$ 1,252,298
Add:			
Deferred Charges	102,101	(3,368)	98,733
Weather Normalization Reserve	10,003	-	10,003
Deferred Energy Replacement Costs	1,030	-	1,030
Cost Recovery Deferral - Depreciation	10,428	-	10,428
Future Income Taxes	435	-	435
Customer Finance Programs	800	1,728	2,528
	124,797	(1,640)	123,157
Deduct:			
Accumulated Depreciation	528,684	-	528,684
Work In Progress	2,314	-	2,314
Contributions in Aid of Construction	23,407	-	23,407
2005 Unbilled Revenue	13,765	-	13,765
Accrued Pension Liabilities	-	3,003	3,003
Accrued OPEBs Liability	-	3,136	3,136
Municipal Tax Liability	-	3,679	3,679
Unit Cost Reserve	1,207	-	1,207
Customer Security Deposits	-	736	736
	569,377	10,554	579,931
Average Rate Base Before Allowances	807,765	(12,241)	795,524
Cash Working Capital Allowance	6,813	2,527	9,340
Materials and Supplies Allowance	4,493	(66)	4,427
Average Rate Base at Year End	$ 819,071	$ (9,780)	$ 809,291

In P.U. 40 (2005) the Board ordered certain changes to the calculation of rate base and return on rate base which became in effect in 2006. The Company was ordered to deduct from rate base the average value of the Unrecognized 2005 Unbilled Revenue which is valued at $21,396,000. This unbilled revenue balance arises as a result of the approval to adopt the accrual method of revenue recognition in 2006. In the second change the Board approved the Company's request to discontinue the use of regulated common equity and substitute book common equity in the calculation of return on rate base.

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland Hydro's proposed demand and energy rate structure. This reserve mechanism is the Purchased Power Unit Cost Variance Reserve used to limit variations in the cost of purchased power associated with the demand and energy rate structure implemented as of January 1, 2005. The net transfer to the reserve for 2006 is $1,342,000 (2005 - $Nil). This results in a reduction to the rate base for 2006.

In P.U. 19 (2003), the Board ordered several changes affecting the calculation of the Company's rate base for 2003 and future years. Beginning in 2003 the Company was ordered to move toward the Asset Rate Base Method for determining its rate base which included incorporating average deferred charges into the calculation of rate base.

The second change affecting rate base in 2003 related to the Weather Normalization Reserve. In P.U. 19 (2003) the Board accepted the Company's proposal to amortize the recovery of the $5,600,000 (after tax) non-reversing portion of the Hydro Production Equalization Reserve over a period of five years commencing in 2003.

See previous section titled *"Company Proposed Changes to Transition to the Asset Rate Base Method ("ARBM")"* for a description of the proposed changes to the calculation of the asset rate base in this Application.

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 testimony is in accordance with established practice and appropriately incorporates proposed changes to transition to the Asset Rate Base Method.

Return on Rate Base

Our procedures with respect to verifying the calculation of forecast return on 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 2002 to 2006 actual return on rate base, the Company's forecast rate of return on rate base for 2007 and 2008 and the upper and lower end of range as set by the Board:

						Forecast		Proposed
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008** (1)	**2008**
Actual Return on Average Rate Base	9.94%	9.03%	8.82%	8.53%	8.57%	8.12%	6.64%	8.82%
Upper End of Range set by the Board	10.24%	9.14%	9.09%	8.86%	8.86%	8.65%	8.65%	9.00%
Lower End of Range set by the Board	9.88%	8.78%	8.73%	8.50%	8.50%	8.29%	8.29%	8.64%

(1) Assumed that Upper and Lower Range to be consistent with 2007.

In P.U. 40 (2006) the Board ordered that a just and reasonable return on rate base for 2007 to be in the range of 8.29% to 8.65%. As noted above, the Company's forecast returns at "Existing 2007 and 2008" are below the range. The Company is proposing the Board approve a return on rate base for 2008 of 8.82%, within a range of 8.64% to 9.00%.

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 testimony has been calculated in accordance with established practice.

Capital Structure

In P.U. 19 (2003) the Board reconfirmed its previous position regarding the capital structure for Newfoundland Power Inc. The Board has deemed that the proportion of common equity in the capital structure shall not exceed 45% and that any common equity in excess of 45% shall not attract a rate of return higher than the rate of return on preferred equity of 6.31%.

Average forecast common equity for 2007 and 2008 including the proposed average common equity for 2008 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) and P.U. 19 (2003).

Based on our recalculations of the components of the capital structure, the Company's projected average capital structure for 2007 and 2008 is as follows:

						Forecast		Proposed
	2002	2003	2004	2005	2006	2007	2008	2008
Debt	54.63%	54.14%	53.80%	53.55%	54.45%	54.75%	55.22%	54.20%
Preferred Equity	1.54%	1.43%	1.33%	1.45%	1.26%	1.19%	1.15%	1.15%
Common Equity	43.83%	44.43%	44.87%	45.00%	44.29%	44.06%	43.63%	44.65%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The above table shows that the Company's forecast average common equity for 2007 and 2008 is within both the approved average common equity by the Board and that recommended by the cost of capital expert, Kathleen McShane, as noted in her direct testimony contained in Volume 3 of the Supporting Materials.

These calculations of capital structure are consistent with Exhibit 5 of the Company's pre-filed evidence.

Calculation of Average Common Equity and Return on Average Common Equity

In compliance with Order 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 rate base beginning in 2006.

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 2007 and 2008 to ensure it was in accordance with established practice.

Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the forecast rate of return on average common equity for 2007 and 2008.

In the 2006 Annual Review report prepared by Grant Thornton it was noted that according to P.U. 19 (2003) the Board ordered that where in a given year the actual rate of return on regulated equity (ROE) is greater than 50 bps above the cost of equity as determined by the Automatic Adjustment Formula, the Company must file a report with its Annual Return explaining the facts and circumstances contributing to the difference. In 2006 the cost of common equity per the Formula was 8.77% (P.U. 39 (2005)). The actual return on book common equity for 2006 was 9.46%. Newfoundland Power has indicated that because the operation of the Formula in 2006 did not result in any change in rates or approved returns from those approved for 2005, the ROE of 9.24% (as approved under P.U. 50 (2004)) is the relevant benchmark to compare the 2006 actual ROE. Under this interpretation, no report is required as the actual ROE is within 50 bps of the approved ROE. An alternative view to Newfoundland Power's interpretation is that the relevant ROE benchmark is the 8.77% which was calculated under the application of the Formula in 2006 (P.U. 39 (2005)) regardless of the fact that there were no changes in rates or approved returns. Under this option the Company would be required to file a report explaining the differences as the actual ROE is 69 bps above the approved ROE.

We recommend that the Board clarify which return on equity benchmark is to be used during periods when approved rates and returns remain unchanged from the previous year.

Interest Coverage

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

						Forecast		Proposed
(000's)	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2008**
Net income	$ 29,420	$ 30,061	$ 31,714	$ 31,317	$ 30,666	$ 29,388	$ 20,446	$ 36,944
Income taxes	16,381	14,945	15,586	15,368	13,639	12,646	14,256	22,357
Interest on long term debt	26,094	30,501	30,165	31,046	32,759	33,564	31,513	31,513
Interest during construction	(454)	(471)	(335)	(319)	(436)	(420)	(350)	(298)
Other interest	2,085	1,042	1,542	1,736	1,502	1,364	2,414	2,257
Total	$ 73,526	$ 76,078	$ 78,672	$ 79,148	$ 78,130	$ 76,542	$ 68,279	$ 92,773
Interest on long term debt	$ 26,094	$ 30,501	$ 30,165	$ 31,046	$ 32,759	$ 33,564	$ 31,513	$ 31,513
Other interest	2,085	1,042	1,542	1,736	1,502	1,364	2,414	2,257
Total	$ 28,179	$ 31,543	$ 31,707	$ 32,782	$ 34,261	$ 34,928	$ 33,927	$ 33,770
Interest coverage (times)	**2.61**	**2.41**	**2.48**	**2.41**	**2.28**	**2.19**	**2.01**	**2.75**

In P.U. 19 (2003) the Board determined that an interest coverage ratio in the order of 2.4 times is acceptable given the Company's level of risk, capital structure and return on equity. From 2002 to 2006 actual interest coverage has been declining from 2.61 in 2002 to 2.28 in 2006. The forecast ratio for 2007 and 2008 under existing rates is 2.19 and 2.01 respectively which is lower than the level identified by the Board in P.U. 19 (2003).

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 2007 and 2008 are based on the expected operating and capital requirements and work plans for 2006, as well as using assumptions, which reflect the best estimate of future economic conditions and events. There is no actual data included within the 2007 forecast.

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. The assumptions were also reviewed for consistency with the direct testimony and other aspects of 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 is consistent with the direct testimony and other aspects of the pre-filed evidence.

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 2008 test year is consistent with the approach used in the 2003 hearing. The forecast for 2008 was prepared in early 2007. Since the last rate hearing, the Company has introduced a new financial system, Great Plains. This financial system has greater functionality than the previous system and enables the Company to better coordinate and assemble expense forecasts.

The guidelines used by the Company in its budgeting process indicates 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 2008 forecast of capital accounts. For example, it was used to escalate the average price of a new service hookup.

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.

The budget coordinator for each department prepares a budget on both a class and breakdown basis based on the department's expected capital and operating requirements and work plans for the next year. Each department forecasts labour costs from work plans and determines the necessary labour requirements. Departmental budgets are consolidated and reviewed in detail by the Finance Department and the appropriate Vice President, and are then presented to the Company's Board of Directors for approval.

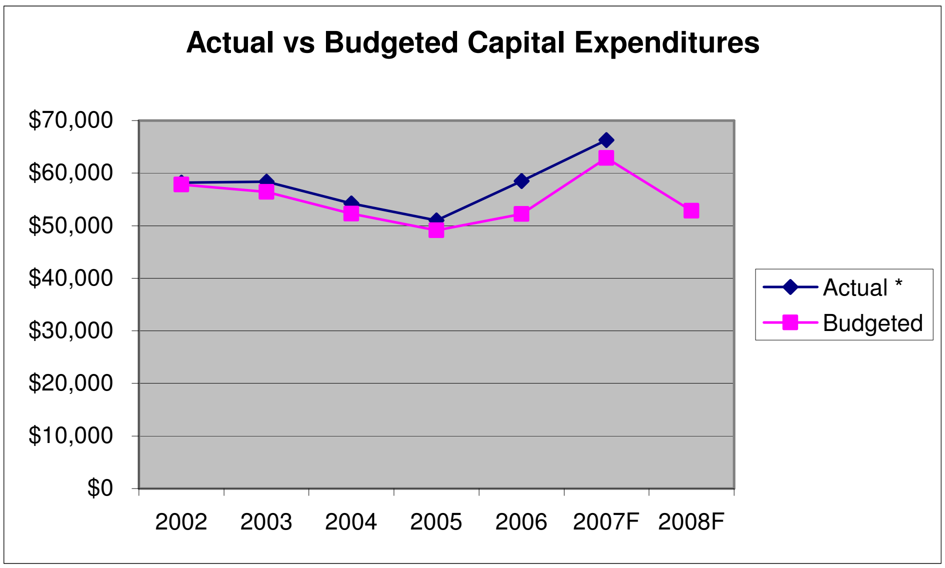
As a result of our review, we have determined that the overall methodology used by the Company for estimating revenue, expenses and net earnings is reasonable and appropriate. Our observations and comments with respect to the reasonableness of individual expense estimates and revenue from rates are included 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 2002 to 2006, including the forecast figures for 2007 and 2008.

	2002	2003	2004	2005	2006	2007F	2008F
Actual *	$58,170	$58,364	$54,255	$50,981	$58,482	$66,309	
Budgeted	$57,839	$56,436	$52,309	$49,151	$52,220	$62,851	$52,854
Over (Under) Budgeted	0.57%	3.42%	3.72%	3.72%	11.99%	5.50%	NA

* The actual figure noted for 2007F is the forecast.



The following charts indicate the capital expenditures including the carry forward of projects from year to year.

Actual

	Projects		
	Current Year	**Carried Forward**	**Total**
2002	58,170	*	58,170
2003	58,364	17,026	75,390
2004	54,255	22,267	76,522
2005	50,981	21,700	72,681
2006	58,482	403	58,885

* This data was not available.

Budget

	Projects		
	Current Year	**Carried Forward**	**Total**
2002	57,839	*	57,839
2003	56,436	15,046	71,482
2004	52,309	20,074	72,383
2005	49,151	21,807	70,958
2006	52,220	350	52,570
2007F	62,851	NA	62,851
2008F	52,854	NA	52,854

* This data was not available.

The above graph demonstrates that from 2002 to 2006, the Company has been consistently over budget on capital expenditures. The Board may wish to continue to monitor this on a go forward basis as part of the capital budget reviews.

From 2002 to 2006, the total capital expenditures have been higher than budget by an average of 4.68% (high: 2006 = 11.99%; low: 2002 = 0.57%).

We have reviewed the significant variances from 2002 to 2006 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 2007 Capital Budget Application, the Company requested approval of $62,200,000 for its 2007 capital program. This budget is larger than recent capital budgets primarily due to the proposed major refurbishment of the Company's largest hydroelectric generating plant at Rattling Brook, which amounts to $18.8 million.

The estimate of 2008 capital expenditures included in this Application is $52,854,000. We understand that a separate Application will be made to the Board in regards to 2008 capital expenditures.

Depreciation

The objective of our procedures in this section was to ensure that the depreciation amounts and rates incorporated in the 2008 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 2007 and 2008; and,

- assessed the overall reasonableness of the estimate of depreciation and true-up amounts for 2007 and 2008.

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.

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

In 2001 the Company changed its calculation of depreciation by using a half-year rule for the calculation of depreciation on net acquisitions (additions less retirements) on a prospective basis. The 2006 Update reflects the use of the half-year rule (mid-year convention), applied on a retroactive basis. The use of the half-year rule for calculating depreciation on net capital additions is very common practice and is in compliance with generally accepted accounting principles.

Gannett Fleming calculated accrued depreciation as of December 31, 2005 at $475.9 million in comparison to the Company's accumulated depreciation of $476.9 million. Gannett Fleming indicates that the calculated accrued depreciation is used as a measure to assess the adequacy of the Company's book accumulated depreciation amount and should not be viewed in exact terms as the correct reserve amount, rather it should be viewed as a benchmark to assess the accumulated depreciation amount based on the most recent information (page 1-6 of Depreciation Study).

The new rates being proposed are effective January 1, 2008.

The following table indicates the depreciation and related cost recovery deferrals from 2002 to 2008E.

	2002	2003	2004	2005	2006	2007F	2008F
Depreciation	$35,442	$29,372	$30,987	$32,143	$38,922	$40,127	$41,002
Cost Recovery Deferrals	0	0	0	0	(5,793)	(5,793)	0
Net Depreciation	$35,442	$29,372	$30,987	$32,143	$33,129	$34,334	$41,002

(Pre-filed evidence, Section 3: Finance, p. 49, Table 18)

The 2008 net deprecation cost is forecast to increase by approximately $6.7 million. The conclusion in 2005 of the reserve variance true-up adjustment accounts for $5.8 million of this increase. The remaining increase of $875,000 in 2008 is due to continued investment in the electricity system. Currently, the Company's revenues do not allow for a full recovery of the depreciation costs. As noted above, this is the result of the use of cost recovery deferrals to offset the impact of the 2005 conclusion of the deprecation true-up. Beginning in 2008, the Company is proposing to fully recover its depreciation costs through its customer rates. As a result, the increased depreciation expense is proposed to be offset in future years by the increase in customer rates.

Gannett Fleming is recommending in this depreciation study that the reserve variance of $694,920, the portion exceeding the 5% tolerance threshold, be amortized over the account's composite remaining life as opposed to the five year period ordered by the Board in P.U. 19 (2003) to amortize the reserve variance at that time.

Based on the information included in Schedule 2 of the Study, the recommended calculation of the reserve variance amortization is based on the following criteria:

- If the reserve variance is greater than 5% and the composite remaining life of the asset is greater than five years, the variance is amortized over the remaining life.
- If the reserve variance is greater that 5% and the composite remaining life of the asset is less than five years, the variance is allocated over five years.
- No reserve variance amortization is calculated when the variance is less than 5%.
- If no assets remain in the account, and no future dismantling costs are expected, the reserve variance is amortized over five years. If future dismantling costs are expected (e.g. steam production plant), the reserve variance is not amortized.

In Board Order P.U. 19 (2003) the Board determined that from the perspective of correcting a depreciation estimate every five years (based on the time frame between depreciation studies) the amortization of the accumulated reserve variance over five years has the quality of intergenerational fairness. The Company has proposed to amortize the 2005 variance over four years, from 2008 to 2011. The reason for the four years versus five is that the four-year amortization matches the period remaining until the next depreciation study is scheduled to be completed. The effect of the four-year versus the five-year amortization would be a $34,000 decrease for each year in the Company's depreciation expense for 2008 to 2011.

The following table details the annual true up provisions over the next five years based on three alternatives.

	2008	2009	2010	2011	2012	**Total**
Composite remaining life	$204,388	$204,388	$204,388	$81,756	$0	$694,920
5 Years	$138,984	$138,984	$138,984	$138,984	$138,984	$694,920
4 Years	$173,730	$173,730	$173,730	$173,730	$0	$694,920

As noted above, the Company has proposed to follow a 4 year amortization of the true-up.

Based on our review of depreciation expense, we conclude that the results and recommendations of the 2006 Update Depreciation Study have been incorporated into the Company's depreciation estimates for 2008.

2008 Test Year Financial Forecast

Based on the evidence included in Exhibit 9 for "Proposed 2008" and "Existing 2008", the Company requires an increase in revenue requirement for 2008 of approximately $27,188,000. This increase is based on the proposals that the Company has put forward relating to the accounting treatment of certain items, a rate of return on rate base 8.82%, a rate of return on common equity of 10.25% and an interest coverage of 2.75 times. The factors contributing to the increase can be summarized as follows:

Components of 2008 Proposed Rate Change
($000s)

	Existing			
	Including Elasticity	**Changes**	**Proposed**	**Rate Change %**
Return on Rate Base	54,527	16,843	71,370	3.3
Other Costs				
Power Supply Costs				
Purchased Power	325,687	2,022	327,709	0.4
Operating Costs	48,723	(833)	47,890	(0.2)
Pension and Early Retirement Costs	3,348		3,348	
OPEB Costs		6,370	6,370	1.2
Amortize Depreciation Deferral		2,317	2,317	0.5
Depreciation	41,002	(795)	40,207	(0.2)
Income Taxes	14,426	7,931	22,357	1.6
	433,186	17,012	450,198	
Total Costs and Return	487,713	33,855	521,568	
Adjustments				
Other Revenue	(10,801)	(1,210)	(12,011)	(0.2)
Non-regulated Expenses	(983)		(983)	
Other Adjustments		92	92	
2008 Revenue	475,929	32,737	508,666	
Amortize Revenue Deferrals		(6,180)	(6,180)	(1.2)
2008 Revenue from Rates	475,929	26,557	502,486	
RSA	22,593		22,593	
MTA	11,868	631	12,499	
Billed to Customers	510,390	27,188	537,578	5.3

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 employee future benefits, amortization of deferred accounts and regulatory reserves, changes to the Automatic Adjustment Formula and the Asset Rate Base Method and depreciation.

The following section reviews forecast operating expenses. Schedule 1 of our report presents the total cost of energy to kWhs sold from 2002 to 2006 and the forecast total cost of energy to forecast kWhs for 2007 and 2008. The table and graph show that the total cost of energy per kWh increased by 8.63% from 2002 to 2006 ($0.0776 to $0.0843) and is forecast to increase by 12.57% from 2006 to forecast 2008 ($0.0843 to $0.0949). This increase is primarily attributable to the increase in purchased power expense due to the increase in rates from Newfoundland and Labrador Hydro.

The effect of all of the factors noted in Newfoundland Power's Application reflect an increased revenue requirement of $27,188,000, which the Company is proposing to obtain by increasing rates effective January 1, 2008 by an average of 5.3%.

Operating Expenses

Using the information in Exhibit 1 of Newfoundland Power's pre-filed evidence and adjusting the gross operating expenses to include the pension and deferred regulatory costs, the gross operating costs per customer and net operating costs per customer from 2002 to forecast 2008 is as follows:

	Actual					Forecast	
(000's)	2002	2003	2004	2005	2006	2007	2008
Number of customers as at year end	219,072	221,653	224,464	227,301	229,500	231,715	233,714
Gross operating expenses (000's)	$52,776	$53,640	$53,794	$55,827	$56,034	$54,612	$53,338
Net operating expenses (000's)	$50,767	$51,799	$51,755	$53,812	$53,996	$52,512	$51,238
Gross operating expense per customer	$241	$242	$240	$246	$244	$236	$228
Net operating expense per customer	$232	$234	$231	$237	$235	$227	$219

Based on the above information, the gross operating expense per customer is forecast to decrease by 5.4% from 2002 to the test year forecast of 2008, and the net operating expense per customer is forecast to decrease by 5.6% for the same period.

Our review of operating expenses was conducted using the breakdown of expenses as outlined in Schedule 2. This schedule provides details of the actual operating expenses for the years 2002 to 2006 as well as the forecast for 2007 and 2008.

Our review focused primarily on the variances in operating expenses from 2006 to forecast 2007 and 2008. The gross operating expenses for 2008 (before transfers to GEC) is forecast to decrease by approximately $2,696,000 in comparison to 2006. This decrease is primarily related to a decline of $3,022,000 in pension expense and a $973,000 decrease in early retirement plan costs. This is partially offset by a $535,000 increase in labour costs, a $417,000 increase in deferred regulatory costs and a $427,000 increase in taxes and assessments.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 4. The table and graph show that the cost per kWh has increased to $0.0112/kWh in 2006 from $0.0111/kWh in 2002 and is forecast to decrease to $0.0103 in 2008. This is primarily due to the reduction of gross operating expenses of $2,696,000 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 Schedule 2, “Operating Expenses by Breakdown” the following key variances have been noted:

- The Company is forecasting total regular and standby labour costs to increase by $725,000 in 2008 versus 2006. According to the Company, wages for unionized employees are scheduled to increase by 3% and 4% for 2007 and 2008 respectively. Managerial wages are scheduled to increase by 3.6% and 3.0% for 2007 and 2008 respectively. According to the Company the scheduled wage increases will be partially offset by productivity improvements.
- Taxes and assessments are forecast to increase by $427,000 in 2007 and 2008 as compared to 2006. This increase is the result of a reduction in the annual assessment rate charged to the Company by the Board in 2006 and a credit of $315,204 received from the Board in 2006 related to prior years.
- Vegetation management costs are forecast to increase 9.5% in 2007 and 2008 as compared to 2006. All of the costs reported in this category relate to contract labour. According to the Company the increase is a result of higher contract prices. Furthermore, a detailed survey of vegetation along power lines was conducted and has identified areas that will need attention in 2007 and 2008.

- Deferred regulatory costs - 2005 was the last year for the amortization of the 2003 deferred regulatory costs, which resulted in a reduction in expenses of $347,000 in 2006. Deferred regulatory costs of $1,250,000 relating to the 2008 rate hearing are forecast to begin amortization over three years starting in 2008, resulting in a $417,000 increase in expenses. This is consistent with the treatment of regulatory costs from the 2003 General Rate Application Hearing.
- Pension and ERP costs are forecast to decrease by $3,022,000 and $973,000 respectively in 2008 compared to 2006. These accounts are reviewed in greater detail further in the report.

Based upon our review and analysis, nothing has come to our attention to indicate that the 2008 forecast operating expenses are unreasonable on an overall basis.

Executive Compensation

The following table provides a summary and comparison of executive compensation for forecast 2007 and 2008 with actuals for 2004, 2005 and 2006.

	Base Salary	Short Term Incentive	(Note 1) Other	Total
Forecast 2008 (Note 1)				
Total executive group	$ 1,153,909	$ 378,618	$ 159,328	$ 1,691,855
Average per executive (5)	**$ 230,782**	**$ 75,724**	**$ 31,866**	**$ 338,371**
Percentage change per executive	2.6%	2.5%	1.9%	2.5%
Forecast 2007 (Note 1)				
Total executive group	$ 1,124,467	$ 369,257	$ 156,357	$ 1,650,081
Average per executive (5)	**$ 224,893**	**$ 73,851**	**$ 31,271**	**$ 330,016**
Percentage change per executive	3.3%	(17.8%)	(6.3%)	(3.2%)
2006				
Total executive group	$ 1,001,379	$ 413,500	$ 153,442	$ 1,568,321
Average per executive (4.6)*	**$ 217,691**	**$ 89,891**	**$ 33,357**	**$ 340,939**
Percentage change per executive	6.2%	(5.5%)	23.6%	4.3%
2005				
Total executive group	$ 1,024,492	$ 475,700	$ 134,892	$ 1,635,084
Average per executive (5)	**$ 204,898**	**$ 95,140**	**$ 26,978**	**$ 327,017**
Percentage change per executive	6.7%	21.9%	(37.1%)	4.5%
2004				
Total executive group	$ 960,429	$ 390,000	$ 214,417	$ 1,564,846
Average per executive (5)	**$ 192,086**	**$ 78,000**	**$ 42,883**	**$ 312,969**
Percentage change per executive	(11.1%)	(22.8%)	0.1%	(12.9%)

* Calculation adjusted for maternity leave of one executive and top-up of EI Benefits.

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.

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.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2004 to forecast 2007 and 2008 is as follows:

				Forecast	
	2004	**2005**	**2006**	**2007**	**2008**
Executive group	8.0	8.2	7.4	8.0	8.0
Corporate office	48.5	43.3	40.1	40.0	39.0
Treasury and finance	59.2	61.9	63.1	63.0	63.0
Customer service	78.0	68.5	72.7	73.3	68.0
Operations	404.9	373.6	369.1	374.3	373.0
	598.6	555.5	552.4	558.6	551.0
Temporary employees	62.2	65.1	70.9	68.4	74.0
Total	660.8	620.6	623.3	627.0	625.0

The most significant change in the above table is the decrease of 40.2 FTE's from 2004 to 2005. This decrease is a direct result of the Early Retirement Plan offered in 2005.

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 2004 to forecast 2007 and 2008 are included in the table below:

Salary Cost Per FTE

				Forecast	
(000's)	**2004**	**2005**	**2006**	**2007**	**2008**
Salary costs	$ 44,568	$ 42,873	$ 44,084	$ 45,368	$ 47,170
Benefit costs (net)	(5,408)	(5,312)	(5,726)	(5,399)	(5,770)
Adjustment relating to clearance accounts	(810)	(390)	247	-	-
Other adjustments	(451)	(269)	(315)	(445)	(585)
Base salary costs	37,899	36,902	38,290	39,524	40,815
Less: executive compensation	(1,344)	(1,500)	(1,415)	(1,494)	(1,533)
Base salary costs (excluding executive)	$ 36,555	$ 35,402	$ 36,875	$ 38,030	$ 39,282
FTE's (including executive members)	660.8	620.6	623.3	627.0	625.0
FTE's (excluding executive members)	655.8	615.6	618.7	622.0	620.0
Average salary per FTE	**57,353**	**59,462**	**61,431**	**63,037**	**65,304**
% increase	**1.72%**	**3.68%**	**3.31%**	**2.61%**	**3.60%**
Average salary per FTE (excluding executive members)	**$ 55,741**	**$ 57,508**	**$ 59,601**	**$ 61,141**	**$ 63,358**
% increase	**2.43%**	**3.17%**	**3.64%**	**2.58%**	**3.63%**

The increasing average salary per FTE in 2007 and 2008 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) Actual			(000's) Forecast	
	2004	2005	2006	2007	2008
Type					
Internal Labour	$ 44,568	$ 42,873	$ 44,084	$ 45,368	$ 47,170
Overtime	3,341	2,565	2,636	2,291	2,068
	47,909	45,438	46,720	47,659	49,238
Contractors	4,853	6,084	9,047	9,015	8,000
	$ 52,762	$ 51,522	$ 55,767	$ 56,674	$ 57,238
Function					
Operating	$ 28,454	$ 28,300	$ 28,136	$ 28,200	$ 28,671
Capital and rechargeable	24,308	23,222	27,631	28,474	28,567
	$ 52,762	$ 51,522	$ 55,767	$ 56,674	$ 57,238

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 2008 are 7.0% higher than 2006. This is consistent with scheduled wage increases for unionized employees of 3.0% for 2007 and 4.0% in 2008. Total labour costs are forecast to increase by 2.6%. The scheduled wage increases for internal labour are partially offset by lower overtime and contractor costs. According to the Company, the 2008 forecast was prepared based on gains made through productivity enhancements permitting internal employees to spend more time on capital and rechargeable projects reducing dependency on contractors.

Short Term Incentive (STI) Program

The Company has indicated that the 2007 and 2008 targets were designed to be consistent with those in 2006. The following table outlines the actual results for 2005 and 2006 and the targets set for 2007 for corporate measures under the STI program:w

Measure	2005 Actual	2006 Actual	2007 Target
Controllable Operating Costs / Customer	$211	$208	207
Earnings	$30.7 m	$30.1 m	$28.6 m
Outage Hours/Customer (SAIDI)	3.27	2.89	N/A
Outage/Customer (SAIFI)	2.56	2.64	2.63
Customer Satisfaction	89%	89%	89%
All Injury/Illness Frequency Rate	1.7	2.8	1.9
Customer Satisfaction - 1st Call Resolution	N/A	N/A	87%

According to the Company, its Corporate SAIDI performance is approaching the Canadian national average and because it is at an acceptable level, has been removed as an STI target measure for 2007. In addition, the Company has implemented a new measure for 2007; the Customer Satisfaction - 1st Call Resolution Target. This statistic measures the percentage of customers who had their issue or inquiry resolved on the first contact to the Company's contact center.

According to the Company, 2008 targets will not be approved by the Board of Directors until January of 2008.

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 2007 and 2008 is established as a percentage of base pay for the three employee groups. The 2007 and 2008 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 2005 and 2006 reflects targets and actual payouts for those years.

STI Payout

	Target 2008	**Target 2007**	**Actual 2006**	**Target 2006**	**Actual 2005**	**Target 2005**
President	N/A	40%	46.2%	35%	53.3%	35%
Vice Presidents	N/A	30%	35.5%	30%	43.5%	30%
Managers	N/A	15%	19.3%	15%	21.3%	15%

In dollar terms the STI payouts forecast for 2007 and 2008 compared to 2003 to 2006 are as follows:

	Actual				Forecast	
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
Executive	$505,000	$390,000	$475,700	$413,500	$369,257	$378,618
Managers	224,180	182,340	221,500	211,200	162,355	165,578
Total	$729,180	$572,340	$697,200	$624,700	$531,612	$544,196

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

Company Pension Plan

For 2007 and 2008, we analyzed the estimates supporting the forecast gross charge for pension expense of $5,378,842, and $3,348,086 respectively. The 2007 expense is forecast to be $1,354,038 lower than the 2006 actual of $6,732,880 and 2008 is forecast to decrease by $2,030,756 from the 2007 estimate.

The components of pension expense are as follows:

			Forecast	
	2005	**2006[1]**	**2007**	**2008**
Pension expense per actuary	$ 4,585,038	$5,788,781	$4,372,338	$2,310,217
Pension uniformity plan/SERP	347,180	376,415	422,182	426,974
Group RRSP @ 1.5%	465,964	451,787	469,859	488,653
Individual RRSP's	112,227	186,984	194,463	202,242
Less: Refunds	(118,388)	(71,087)	(80,000)	(80,000)
Total Pension Expense	$ 5,392,021	$ 6,732,880	$ 5,378,842	$ 3,348,086

Pension expenses relating to the 2005 Early Retirement Program are included in the analysis above. The principal reason for the increased pension expense in 2006 compared to 2005 was that the discount rate used to determine the annual pension expense was lowered from 6.25% to 5.25% in 2006. The discount rate is changed each December 31st based upon prescriptive requirements of the Canadian Institute of Chartered Accountants ("CICA") Handbook.

Pension expense is forecast to decrease in 2007 and 2008 relative to 2006. According to the Company, the primary reason for the decrease is that the actuarial report filed with the Application predicts that the defined benefit plan's past service obligations will be fully funded in 2008. This results in an increase in plan assets which increases returns resulting in a net decrease in pension expense.

[1] Note that pension expenses for 2006 noted above are $13,000 higher than noted in schedule 2. According to the Company, there was a $13,000 recovery from the Belize Electrical Company as a result of the retirement of an employee who was on secondment. This recovery is not reflected in the table above but has been noted on schedule 2.

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. The Group RRSP expense will increase year over year with the number of new hires at the Company.

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.

Retiring Allowance

The retiring allowance costs from 2003 to 2006 and forecast 2007 and 2008 are as follows:

					Forecast	
(000)'s	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Early Retirement Program			$1,012	$ 624	$ 134	
Terminations and Severance	$ 328	$ 210	11	9	20	$ 20
Normal Retirements	-	15	-	205	155	155
Other Retiring Allowance Costs	8	8	37	4	-	-
Total	$ 336	$ 233	$1,060	$ 842	$ 309	$ 175

During the first quarter of 2005, 76 employees retired under a voluntary Early Retirement Program which was authorized by the Board per P.U. 49 (2004). The resulting retirement allowance of $1,684,000 is currently being amortized over 24 months which began on April 1, 2005, with $1,012,000 being recognized in 2005, $538,000 in 2006 and $134,000 in 2007. The Company has not planned to offer employees any similar programs in 2007 or 2008. Therefore it has only forecast for normal retirements to occur during the forecast period. Retiring allowance costs related to the Early Retirement program are expensed under the "ERP (retirement allow and pension)" line of Schedule 2 while the remainder of the retiring allowances shown above are expensed under Retirement allowances.

Intercompany Charges

Our review of Intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003);
- Compared charges for 2007 & 2008 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 2004 through 2006, including forecast charges for 2007 and 2008:

Inter-Corporate Charges to Affiliates

				Forecast	
	2004	**2005**	**2006**	**2007**	**2008**
Printing & Stationary	$ 19,058	$ 11,326	$ 6,187	$ 5,600	$ 5,700
Postage	13,626	18,243	17,683	18,000	18,300
Staff Charges	1,484,891	751,510	1,019,501	675,000	698,600
Staff Charges - Insurance	151,102	163,340	143,748	145,000	150,100
Insurances	243	-	-	-	-
IS Charges	363,203	21,767	30,353	19,700	20,100
Pole Installations	809,010	304,246	60,134	17,200	17,500
Miscellaneous	576,642	115,267	43,857	35,500	36,200
Total	$ 3,417,775	$ 1,385,699	$ 1,321,463	$ 916,000	$ 946,500

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

- In 2006 staff charges increased by $267,991 over 2005. This increase related primarily to employee secondment costs charges to Belize Electricity.
- In 2004 staff charges to Fortis Inc. were $1,163,762 versus $388,539 in 2005. The 2004 charges were for the restoration of an electricity system in Grand Cayman, after it was severely damaged by Hurricane Ivan in September 2004.
- Prior to 2005 the Company paid for the licensing costs of Microsoft software and subsequently billed affiliated companies. Microsoft now bills the Company for it's licensing costs only causing a decrease in IS charges.
- Previously, the Company was billed by contractors for pole installation costs. According to the Company this practice was changed in the fourth quarter of 2005. Fortis Inc. is now billed for these costs causing a decrease in pole installation costs.
- Miscellaneous charges to affiliates have dropped significantly since 2004. According to the Company, miscellaneous charges were higher from 2002 through 2004 as a result of executive transfers to other affiliates and miscellaneous expenses related to the Cayman Islands Hurricane relief in 2004. Also, in 2006 the Company stated that it discontinued bill printing services to Maritime Electric.

The following table provides a breakdown of regulated inter-corporate charges from affiliates from 2004 through 2006, including forecast charges for 2007 and 2008:

Regulated charges from affiliates				Forecast	
	2004	**2005**	**2006**	**2007**	**2008**
Trustee fees	$ 106,207	$ 71,241	$ 73,396	$ 79,800	$ 79,800
Listing and filing fees	30,946	15,360	16,927	22,800	22,800
Miscellaneous	57,945	182,730	881,976	20,000	3,400
Hotel/Banquet facilities & meals (1)	34,327	33,942	20,312	15,000	15,000
Staff charges	20,824	3,377	21,880	-	-
	$ 250,249	$ 306,650	$ 1,014,491	$ 137,600	$ 121,000

The most significant observation from our analysis of charges from related companies is as follows:

- Miscellaneous expenses increased by $699,246 from 2005 to 2006. 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. According to the Company, the amounts for joint use transfers for 2007 and 2008 could not be determined as the number of poles that will be transferred is unknown. Also, meter refurbishments were awarded to a non-affiliated supplier in early 2007 eliminating this expense from miscellaneous charges from affiliates.

As a result of completing our procedures, nothing has come to our attention to indicate that intercompany charges for 2007 and 2008 and are not in compliance with Board orders.

Interest and Finance Charges

The following table summarizes the various components of finance charges:

	Actuals				**Forecast**	
(000's)	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Interest						
Long-term debt	$ 30,501	$ 30,165	$ 31,046	$ 32,759	$ 33,564	$ 31,513
Other	762	1,277	1,535	1,309	1,582	2,562
Amortization						
Debt discount	198	199	201	193	202	188
Capital stock issue	82	66	64	62	62	62
Interest charged to construction	(471)	(335)	(319)	(436)	(420)	(350)
Interest earned	(1,063)	(979)	(1,158)	(1,210)	(1,200)	(1,200)
Total finance charges	$ 30,009	$ 30,393	$ 31,369	$ 32,677	$ 33,790	$ 32,775

As per our analysis of the detailed transactions, interest earned is comprised substantially of revenue earned for service application fees and late payment charges.

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

The total finance charges were analyzed as a percentage of average debt. Finance charges as a percentage of average debt are forecast to drop from 8.06% in 2006 to 7.27% in 2008. According to the Company, this is primarily the result of the maturing of Series AC First Mortgage Bonds carrying a coupon rate of 11.875%. These are forecast to be replaced by a $60.0 million bond issue in August of 2007 at an interest rate of 5.50%. Given the increase in overall debt at a lower borrowing rate, forecast finance charges as a percentage of debt are not unreasonable.

Other interest which includes interest on short term debt, is forecast to increase significantly for 2007 and 2008. However, this coincides with the fact that short term debt is forecast to increase. We have reviewed the short term interest rates included in the Company's assumptions and they appear reasonable.

The Company's forecast of interest earned and interest charged to construction are consistent with prior years.

Other expense categories

We have reviewed the other categories of expenses included in Schedule 2 and compared the 2008 test year to prior years and have investigated any unusual variances.

Purchased Power

We have reviewed the Company's purchased power expense forecast for 2007 and 2008 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 2007 has increased by $65,468,000 over the 2006 actual, which represents a 25.5% increase. On a unit cost level, the increase from $0.05274 in 2006 to $0.06493 in 2007 represents a 23.1% increase. The 2008 forecast, with proposed changes, shows an increase of an additional $5,021,000 due to increased sales and an increase in unit cost of approximately 1.0% from 2007 to $0.06534.

This increase is due to a combination of several factors:

- rate increases from Newfoundland and Labrador Hydro, as noted in their 2006 rate hearing, results in an average base rate increase of 26.5% for Newfoundland Power. In 2007 the Holyrood fuel cost included in rates increased from approximately $29 per barrel to $55 per barrel, which is the primary driver for the percentage increase in the power supply unit cost from 2006 to 2007;

- the Company is forecasting a 1.2% increase in consumption in both residential and commercial markets due to general economic growth in 2007 and a further 2% increase in 2008; and
- additional purchases are required to serve the additional customer load requirements in the future.

Based upon our analysis, purchased power forecast for 2008 appears consistent with changes in the mil rate and forecast increases in energy sales.

Non-Regulated Expenses

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

- assessed the Company's compliance with P.U. 19 (2003); and
- compared non-regulated expenses for the 2008 forecast to prior years and investigated any unusual fluctuations:

Non-regulated expenses					**Forecast**
	2004	**2005**	**2006**	**2007**	**2008**
Billed by Fortis	$ 863,700	$ 724,700	$ 804,900	$ 733,000	$ 762,000
Non-regulated expenses - general	623,200	376,500	664,600	523,000	469,000
Corporate donations and Advertising	336,700	306,600	298,100	270,000	270,000
Non-regulated expenses before tax	1,823,600	1,407,800	1,767,600	1,526,000	1,501,000
Less: income taxes	(520,400)	(492,700)	(618,700)	(551,000)	(518,000)
Non-regulated expenses after tax	$ 1,303,200	$ 915,100	$ 1,148,900	$ 975,000	$ 983,000

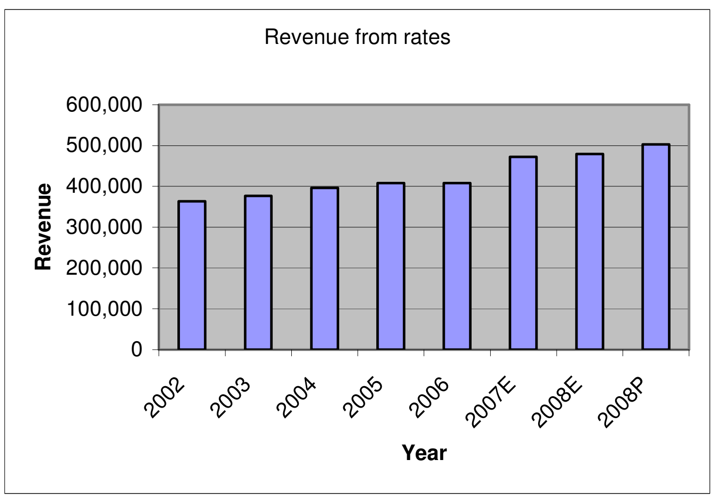
The 2008 non-regulated expenses have been forecast at $983,000 (after tax) as compared to $1,148,900 in 2006. The decrease was mainly attributable to a $350,000 pension expense adjustment made in 2006.

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. 19 (2003).

Proposed Forecast Revenue

We have compared the actual revenues for 2002 to 2006 to the forecast revenues as proposed by the Company for 2007 to 2008 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

						Existing	Existing	Proposed
	Actual					Forecast		
(000's)	2002	2003	2004	2005	2006	2007	2008	2008
Residential	$ 216,375	$ 224,263	$ 236,087	$ 243,852	$ 244,121	$ 282,572	$ 286,965	$ 303,824
General Service								
0-10 kw	10,825	10,906	11,300	11,510	11,269	12,434	12,555	12,642
10-100 kw	47,450	48,738	51,160	52,853	53,343	61,539	62,479	63,736
110-1000 kva	54,370	56,687	59,707	61,037	60,261	71,426	71,961	75,247
Over 1000 kva	20,944	22,186	23,570	24,280	24,556	29,299	29,569	31,244
Streetlighting	10,713	10,995	11,343	11,524	11,658	12,175	12,258	12,920
Discounts forfeited	2,095	2,319	2,410	2,541	2,481	2,710	2,748	2,873
Revenue from rates	362,772	376,094	395,577	407,597	407,689	472,155	478,535	502,486
	2.78%	3.67%	5.18%	3.04%	0.02%	15.81%	1.35%	6.42%



The following is a summary of the rate changes approved by the Board from 2002 to 2007 and the Company's request for 2008 (all rates provided here exclude adjustments relating to Rate Stabilization Adjustment or the Municipal Tax Adjustment):

- 2002 - 0.56% decrease effective January 1, 2002
- 2002 - 3.68% increase effective September 1, 2002
- 2003 - 0.15% decrease effective August 1, 2003
- 2004 - 5.56% increase effective July 1, 2004
- 2005 - 0.54% decrease effective January 1, 2005
- 2007 - 13.88% net increase effective January 1, 2007
- 2008 - 5.55% proposed increase effective January 1, 2008 as a result of this 2008 general rate application.

According to the table on the previous page, the Company's revenues have been increasing by various percentages since 2002. The Company has noted the following reasons for the changes in the revenue levels from 2002 to 2006.

- The 2.78% increase in revenue in 2002 over 2001 is a result of customer and sales growth combined with a September 1, 2002 rate increase from the 2001 Hydro general rate application, offset partially by a rate decrease as a result of the implementation of the Automatic Adjustment Formula in January 1, 2002.

- The 3.67% increase in 2003 over 2002 was primarily due to customer and sales growth offset partially by the August 1, 2003 rate decrease as a result of the 2003 general rate application for Newfoundland Power.

- The 2004 increase of 5.18% is a result of customer growth coupled with the July 1, 2004 rate increase resulting from the 2003 Hydro general rate application.

- For 2005 the increase in revenues was 3.04% over 2004. This increase was due to customer and sales growth along with the rate increase of July 1, 2004 offset partially by the decrease beginning January 1, 2005 resulting from the operation of the Automatic Adjustment Formula.

- The 2006 revenue was stable with 2005. There were no rate changes impacting customers between 2005 and 2006.

- The 2007 forecast increase in revenue of 15.81% over 2006 is primarily a result of the net rate increases of 13.88% effective January 1, 2007 combined with forecast customer and sales growth.

- The 2008 forecast increase in revenues using existing rates in effect as of January 1, 2007 is 1.35% over the 2007 forecast. Under the new rates proposed in this Application the increase in revenues for 2008 is forecast at 6.42%.

The number of customers and the GWh's sold to these customers for 2002 to 2006 and forecast 2007 and proposed 2008 are as follows:

	Actual					Forecast		
						Existing	Existing	Proposed
	2002	2003	2004	2005	2006	2007	2008	2008
Customers	219,072	221,653	224,464	227,301	229,500	231,715	233,714	233,714
% Change	1.01%	1.18%	1.27%	1.26%	0.97%	0.97%	0.86%	0.86%
GWh Sold	4,765	4,882	4,979	5,004	4,995	5,054	5,154	5,121
% Change	2.10%	2.46%	1.98%	0.51%	-0.18%	1.18%	1.98%	1.32%

As the above table indicates, from 2002 to 2006 the number of customers is increasing at an average annual increase of 1.14 %. GWh's sold has increased at an average annual rate of 1.37% from 2002 to 2006.

The impact by rate class of the overall increase in customer rates of 5.3% is detailed on page 4 of the Application. Included in the Company Evidence to the Application it is noted that the general impacts of these increases are as follows:

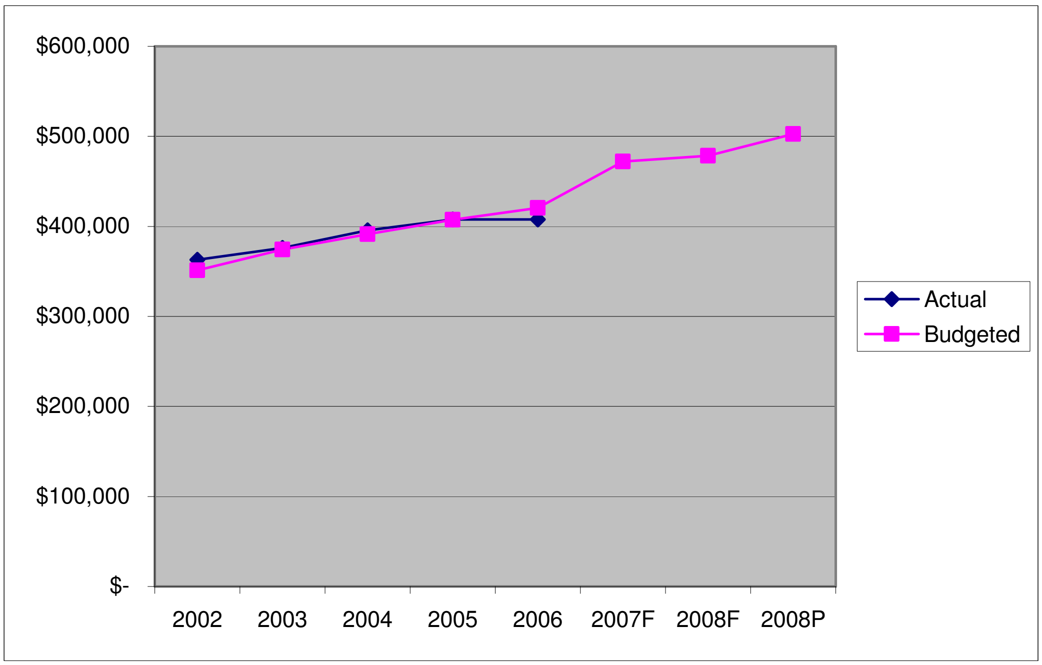
- Customers with higher energy usage will receive higher percent rate increases.
- General Service customers served under Rate 2.1 will all experience approximately the same dollar increase.
- General Service customers under Rates 2.2, 2.3 and 2.4 will receive increases that vary depending on load factor. Higher load factor customers (high energy use relative to billing demand) will experience higher percentage increases and low load factor customers will experience increases that approximate the overall proposed average rate increase.

The following table details the actual versus budgeted revenues from rates for the past 5 years from 2002 to 2006, the forecast 2007 and 2008 revenues and the proposed 2008 revenues.

(000's)	2002 (1)	2003	2004	2005	2006 (2)	2007F	2008F	2008P
Actual	$362,772	$376,094	$395,577	$407,597	$407,689			
Budgeted	$351,124	$374,149	$391,240	$407,367	$420,613	$472,155	$478,535	$502,486
Over (Under) Budgeted	3.32%	0.52%	1.11%	0.06%	(3.07%)			

(1) 2002 budgeted revenue did not reflect the September 1, 2002 rate increase as a result of the Hydro Flow-Through.

(2) Revenue has been normalized for the 2005 Unbilled Revenue adjustment.



In assessing the validity of the 2007 and 2008 forecast revenues, we agreed all forecast amounts to supporting schedules provided by the Company. In addition, we also 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 2007 and 2008 appear unreasonable.

The Company's other revenue from 2002 to 2006 and as forecast for 2007 and 2008 is as follows:

($000s)	**2002**	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Pole Attachment	5,385	6,395	7,194	8,238	8,346	8,606	9,060
Miscellaneous	1,470	1,661	1,676	2,014	2,143	1,820	1,741
Interest				2,114			
Total	**6,855**	**8,056**	**8,870**	**12,366**	**10,489**	**10,426**	**10,801**

The large increase in other revenue in 2005 was due to $2,100,000 in interest revenue resulting from a CRA income tax settlement. Other revenue variations from 2002 to 2006 are a result of revenue from pole attachments. The forecasts for 2007 and 2008 include continued increases in revenue from pole attachments. The Company is estimating that joint-use poles will increase by 3.4% from 2006 to 2008.

Proposed Revenue from Rates

The Company is proposing the Board approve rates, tolls and charges effective for service provided on and after January 1, 2008, to provide an average increase by class in electrical rates of 5.3%, based upon:

a) a forecast average rate base for 2008 of $809,291,000;
b) a rate of return on average rate base for 2008 of 8.82% in the range of 8.64% to 9.00%; and
c) a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in paragraphs 15, 16 and 17 of the Application, of $502,486,000 for 2008.

We have reviewed the Company's proposed new rates effective January 1, 2008. 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 2007 and 2008 revenues by rate class with the proposed increases:

	Existing Rates	Proposed Rates	Change ($)	Change (%)
DOMESTIC - RATE # 1.1 **(1)**				
Basic Customer Charge (Monthly)	$15.59	$15.59	$0.00	0.00%
Energy Charge - All Kilowatt Hours (Cents/kWh)	8.935¢	9.586¢	0.651¢	7.29%
G.S. 0-10 kW - RATE # 2.1				
Basic Customer Charge (Monthly)	$17.88	$19.08	$1.20	6.71%
Energy Charge - All Kilowatt Hours (Cents/kWh)	11.462¢	11.462¢	0.000	0.00%
G.S. 10-100 kW - RATE # 2.2				
Basic Customer Charge (Monthly)	$20.60	$20.60	$0.00	0.00%
Energy Charge (Cents/kWh)				
First 150 kWh	9.108¢	9.108¢	0.00¢	0.00%
All Excess kWh	6.102¢	6.799¢	0.697	11.42%
G.S. 110-1000 kVA - RATE # 2.3				
Basic Customer Charge (Monthly)	$92.73	$92.73	$0.00	0.00%
Energy Charge (Cents/kWh)				
First 150 kWh (max. 30,000)	8.722¢	8.886¢	0.164	1.88%
All Excess kWh	5.974¢	6.645¢	0.671	11.23%
G.S. 1000 kVA - RATE # 2.4				
Basic Customer Charge (Monthly)	$185.46	$185.46	$0.00	0.00%
Energy Charge (Cents/kWh)				
First 100 kWh	7.334¢	7.403¢	0.069	0.94%
All Excess kWh	5.866¢	6.501¢	0.635	10.83%

(1) Overall increase for Domestic rate class taking into account Basic Customer Charge is 6.4%.

The proposed overall increase in rates of 5.33% is mainly attributable to a proposed increase in residential rates of 7.29% which accounts for the greatest usage of electricity. This is partially offset by proposed increases in other classes which are lower on average than the 5.33% composite.

Based on our procedures, we find that the revenue requirement as proposed by the Company is calculated upon the revised Schedule of Rates, Tolls and Charges effective January 1, 2008 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.

During our review, we examined the latest changes to the system of accounts which were filed with the Board. On June 14, 2006, the Company filed a summary of revisions to its system of accounts with the Board. As reported upon in the 2006 annual review, the Company noted that the revisions are a result of accounting changes and reporting requirements arising from orders of the Board and changes in accounting standards announced by the Canadian Institute of Chartered Accountants. In addition, the Company had made some minor revisions to improve the clarity and accuracy of the account descriptions. The revisions consisted of the addition of new accounts, the deletion of older accounts that have been replaced by other accounts, as well as account description changes. Specifically, P.U. 10 (2007) approved a revised definition of the Purchased Power Unit Cost Variance Reserve Account.

Changes to the system of accounts since 2003, the date of last rate hearing, include the following: P.U. 23 (2003) which approved the Company's revised definition of the Excess Earnings Account; P.U. 50 (2004) which further approved the Company's revised definition of the Excess Earnings Account; and, P.U. 35 (2005) which approved the Company's definition of the Purchased Power Unit Cost Variance Reserve Account.

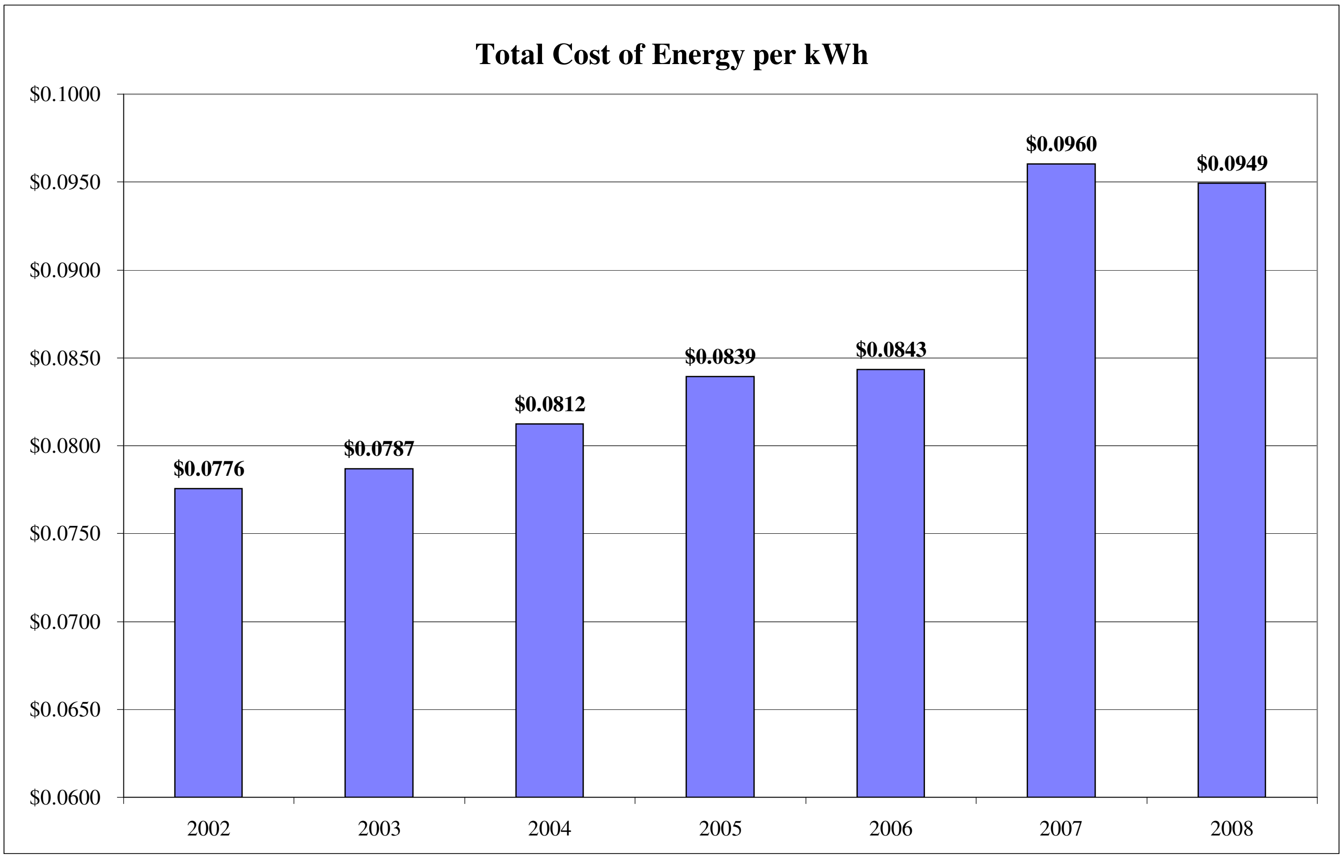
All changes discussed above are consistent with P.U. Orders issued by the Board.

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

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
2002	4,765,000	$ 50,767	$ 210,764	$ 35,442	$ 26,853	$ 16,381	$ 29,420	$ 369,627	$ 0.0776
2003	4,882,000	$ 51,799	$ 227,964	$ 29,372	$ 30,009	$ 14,945	$ 30,061	$ 384,150	$ 0.0787
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	5,054,000	$ 52,512	$ 322,625	$ 34,334	$ 33,790	$ 12,646	$ 29,388	$ 485,295	$ 0.0960
2008	5,154,000	$ 52,071	$ 328,786	$ 41,002	$ 32,775	$ 14,256	$ 20,446	$ 489,336	$ 0.0949

* 2006 and 2007 depreciation has been reduced by $5,793,000 related to the deferral of the 2006 True-up
** 2008 operating expenses include $1,250,000 related to 2008 GRA costs
*** Table based on information provided in Exhibit 5 of the Supporting Materials to the GRA



Newfoundland Power Inc. **Schedule 2**
Operating Expenses by Breakdown (Table)
(000's)

	Breakdown	Actual					Forecast	
		2002	2003	2004	2005	2006	2007	2008
1	Regular and standby	$ 24,962	$ 23,674	$ 24,689	$ 24,568	$ 24,463	$ 24,642	$ 25,188
2	Temporary	1,545	1,723	2,097	2,232	2,204	2,127	2,040
3	Overtime	1,903	1,759	1,668	1,500	1,469	1,431	1,443
4	**Total Labour**	**$ 28,410**	**$ 27,156**	**$ 28,454**	**$ 28,300**	**$ 28,136**	**$ 28,200**	**$ 28,671**
5	Vehicle expenses	1,502	1,743	1,334	1,482	1,495	1,482	1,495
6	Operating materials	1,564	1,486	1,555	1,432	1,232	1,137	1,124
7	Inter-company charges	626	769	667	489	575	560	568
8	Plans, subs, system oper & bldgs	2,055	2,119	1,850	1,813	1,925	1,822	1,820
9	Travel	1,220	1,072	1,095	1,063	1,105	1,062	987
10	Tools and clothing allowance	799	1,000	962	899	822	835	836
11	Miscellaneous	1,635	1,654	1,684	1,463	1,421	1,457	1,486
13	Taxes and assessments	823	866	784	660	253	680	680
14	Uncollectible bills	700	1,108	963	1,158	961	1,000	1,050
15	Insurances	1,098	1,389	1,510	1,653	1,696	1,728	1,775
16	Retirement allowances	59	336	233	48	218	175	175
17	Education, training, employee fees	318	258	216	245	252	238	248
18	Trustee and directors' fees	339	406	375	388	373	386	395
19	Other company fees	1,909	2,187	1,434	1,697	1,605	1,609	1,418
20	Stationery & copying	354	376	274	326	380	394	372
21	Equipment rantal/maintenance	825	708	695	717	707	763	725
22	Telecommunications	1,511	1,598	1,626	1,694	1,656	1,620	1,630
23	Postage	1,294	1,364	1,406	1,506	1,537	1,465	1,571
24	Advertising	302	281	368	326	381	368	371
25	Vegetation management	987	997	1,051	1,070	1,278	1,361	1,400
26	Computing equipment & software	474	633	566	682	683	758	776
27	**Total Other**	**$ 20,394**	**$ 22,350**	**$ 20,648**	**$ 20,811**	**$ 20,555**	**$ 20,899**	**$ 20,902**
28	**Sub Total**	**$ 48,804**	**$ 49,506**	**$ 49,102**	**$ 49,111**	**$ 48,691**	**$ 49,099**	**$ 49,573**
29	Deferred regulatory costs*	$ -	$ 347	$ 347	$ 347	$ -	$ -	$ 417
30	Pension costs	3,829	3,787	4,345	4,511	5,242	4,251	2,220
31	ERP (retirement allow and pension)	143	-	-	1,858	2,101	1,262	1,128
32	Other employee future benefits	-	-	-	-	-	-	-
32	**Total Gross Operating Expenses**	**$ 52,776**	**$ 53,640**	**$ 53,794**	**$ 55,827**	**$ 56,034**	**$ 54,612**	**$ 53,338**
33	Transfer to GEC	(2,009)	(1,841)	(2,039)	(2,015)	(2,038)	(2,100)	(2,100)
34	**Net Operating Expenses**	**$ 50,767**	**$ 51,799**	**$ 51,755**	**$ 53,812**	**$ 53,996**	**$ 52,512**	**$ 51,238**

* Based on amortization of 2008 GRA costs over 3 years

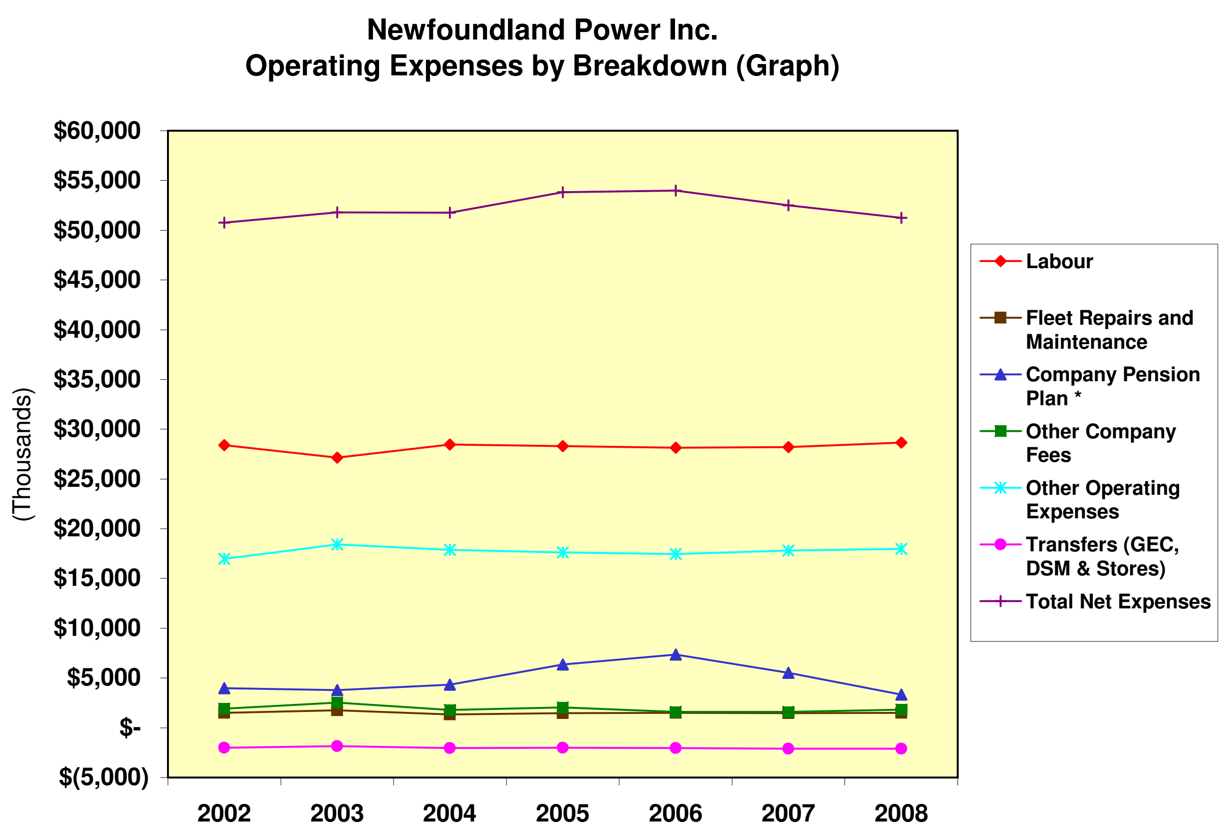
** Table based on Exhibit 1 of the Supporting Materials to the GRA

Newfoundland Power Inc.
Operating Expenses by Breakdown (Graph)
(000's)

Schedule 3

	Actual					Forecast	
	2002	2003	2004	2005	2006	2007	2008
Labour	$ 28,410	$ 27,156	$ 28,454	$ 28,300	$ 28,136	$ 28,200	$ 28,671
Fleet Repairs and Maintenance	1,502	1,743	1,334	1,482	1,495	1,482	1,495
Company Pension Plan *	3,972	3,787	4,345	6,369	7,343	5,513	3,348
Other Company Fees	1,909	2,534	1,781	2,044	1,605	1,609	1,835
Other Operating Expenses	16,983	18,420	17,880	17,632	17,455	17,808	17,989
Transfers (GEC, DSM & Stores)	(2,009)	(1,841)	(2,039)	(2,015)	(2,038)	(2,100)	(2,100)
Total Net Expenses	**$ 50,767**	**$ 51,799**	**$ 51,755**	**$ 53,812**	**$ 53,996**	**$ 52,512**	**$ 51,238**

* Includes Pension costs and ERP costs.

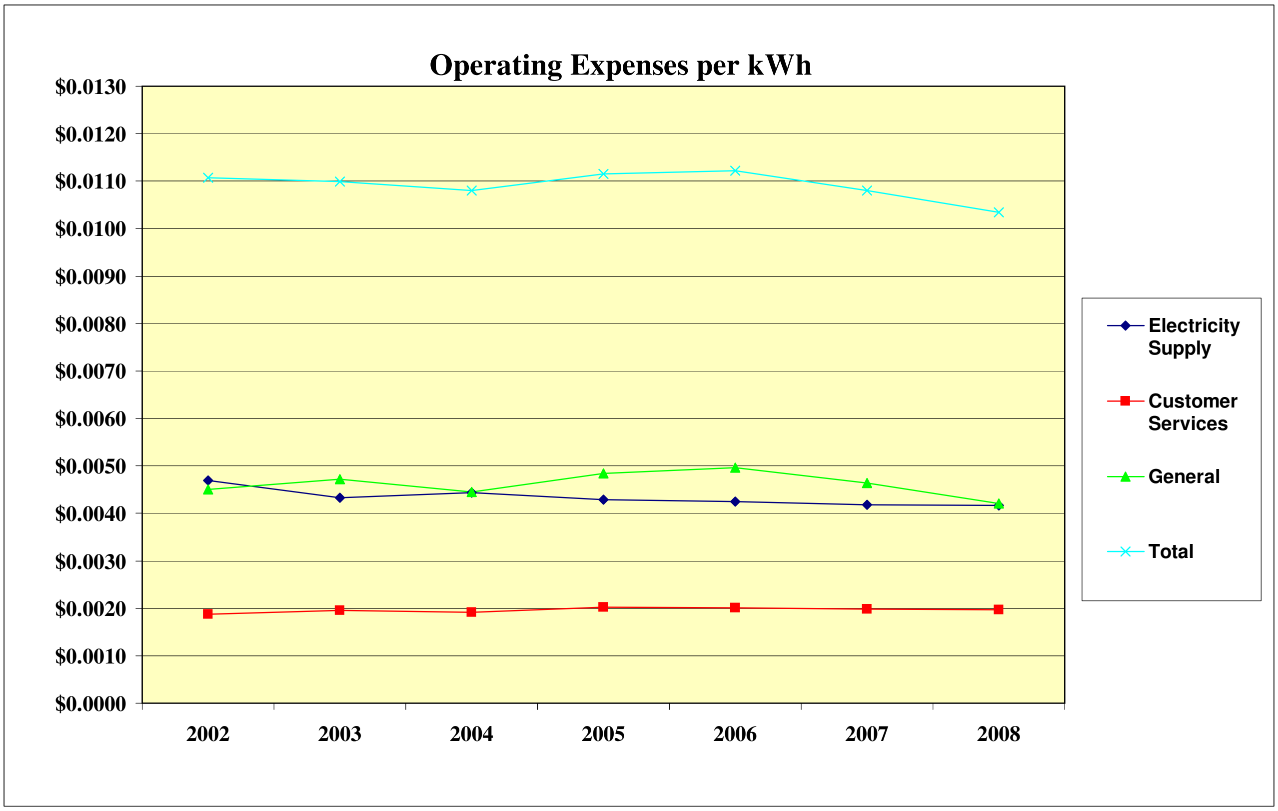


Newfoundland Power Inc.
Comparison of Gross Operating Expenses to kWh Sold
(000's)

Schedule 4

		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
2002	4,765,000	$ 22,376	$0.0047	$ 8,928	$0.0019	$ 21,472	$0.0045	$ 52,776	$0.0111
2003	4,882,000	$ 21,109	$0.0043	$ 9,519	$0.0019	$ 23,012	$0.0047	$ 53,640	$0.0110
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	5,054,000	$ 21,137	$0.0042	$ 10,020	$0.0020	$ 23,455	$0.0046	$ 54,612	$0.0108
2008	5,154,000	$ 21,480	$0.0042	$ 10,144	$0.0020	$ 21,714	$0.0042	$ 53,338	$0.0103

* Includes deferred regulatory costs, pension and early retirement program costs.



Electricity Supply = Operating Expenses less Purchased Power
General Expenses = General Expenses less Customer Service