SECTION 1: INTRODUCTION

1.1 Overview

On May 10, 2007, Newfoundland Power filed a general rate application to establish customer electricity rates for 2008 (the "Application"). On October 11, 2007, Newfoundland Power filed an amended 2008 general rate application (the "Amended Application").

The Amended Application incorporates two essential categories of changes to the Application: (i) revisions that result from changes in 2008 forecasts of costs and sales; and (ii) revisions that result from a settlement agreement reached in relation to proposals contained in the Application (the "Settlement Agreement").

The incorporation of the revisions that result from changes in the 2008 forecasts of costs and sales provide the Board with the most current forward-looking information upon which to establish 2008 electricity rates.

The incorporation of the revisions which result from the Settlement Agreement is consistent with recent regulatory process developments before the Board which encourage more negotiated and mediative resolution of regulatory issues.

The Amended Application seeks an average increase in current customer rates of approximately 2.8 percent in 2008. The increase is proposed to vary among customer classes. For Domestic customers, the average increase sought is 3.9 percent; for smaller General Service customers served under Rate 2.1, an average decrease of 1.2 percent is sought.

1.2 The Amended Application

In the Amended Application, Newfoundland Power seeks an average increase in current customer rates of approximately 2.8 percent in 2008. This increase results from two primary changes in Newfoundland Power's costs.

Depreciation cost recovery accounts for an approximate 1.8 percent increase in 2008 revenues. This increase is principally due to the 2005 conclusion of the reserve variance true-up.[1]

An approximate 0.4 percent increase in 2008 revenues is attributable to revising the Company's 2008 return on rate base to reflect a return on common equity for ratemaking purposes of 8.95 percent.[2]

An approximate 0.3 percent increase in 2008 revenues is attributable to recovering increased supply costs to serve customer load growth.[3]

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[1] Depreciation recovery in 2007 was $34,334,000 (see Section 3.2.4, Table 18, p. 49 of the Application, $40,127,000 depreciation expense minus $5,793,000 depreciation cost recovery deferral). Depreciation recovery in 2008 is forecast to be $40,208,000. The increase in 2008 depreciation costs over 2007 is $5,874,000 ($40,208,000 minus $34,334,000). This increases the 2008 depreciation recovery by $8,968,000 ($5,874,000 divided by (1 minus 34.5 percent tax rate)). This will result in a revenue increase of 1.8 percent in 2008 ($8,968,000 divided by $485,692,000 (existing rate revenue)).

[2] 8.95 percent minus 8.6 percent (2007 ratemaking return) equals 0.35 percent. 0.35 percent times $365,341,000 (2008 average book equity) equals $1,279,000. $1,279,000 divided by 0.655 (1 – tax rate) equals $1,952,000. $1,952,000 divided by $485,692,000 (existing 2008 forecast revenue per Exhibit 9 (1st Revision)) equals 0.40 percent.

[3] A 1.2 cent per kWh negative marginal contribution on growth in purchases exists under current rates in 2008 (see Table 38, page 92 in the Application). This results in a forecast shortfall in 2008 supply cost recovery of approximately $1,474,000 for 2008 (1.2 cents per kWh times 122.8 GWh growth in purchases due to sales growth forecast under existing rates from 2007 to 2008). The $1,474,000 divided by $485,692,000 (existing 2008 forecast revenue per Exhibit 9 (1st Revision) equals 0.3 percent.

In addition to these costs, other proposals in the Amended Application also affect the 2008 revenue requirement such as those relating to the amortization of revenue and cost deferrals and the adoption of accrual tax accounting for pensions.

1.3 Summary of Changes

In the Application, Newfoundland Power requested an average increase in customer rates of approximately 5.3 percent in 2008. In the Amended Application, Newfoundland Power is requesting an average increase in customer rates of approximately 2.8 percent in 2008. The change in the requested 2008 average rate increase results from the revisions to the 2008 forecasts of costs and sales and the Settlement Agreement.

Table 1 summarizes the approximate impact on customer rates of the changes to the Application presented in the Amended Application.

Table 1
Amended Application Revisions
2008 Rate Impacts
(percent)

	Rate Impact
Application	5.5[4]
Forecast Cost and Sales Revisions	0.3
Settlement Agreement Revisions	(3.0)
Amended Application	**2.8**

[4] The 5.3 percent average rate increase sought in the Application was based upon rates in effect at the May 10, 2007 date of filing. As of July 1, 2007, customer rates were reduced by 2.9 percent. At the time of filing the Amended Application in October 2007, an approximate customer rate increase of 5.5 percent would be required on current rates to achieve a revenue increase equal to that yielded by a 5.3 percent increase on rates in effect on May 10, 2007. This difference is expressed arithmetically as follows 5.3 ÷ (1 - .029) = 5.5.

The forecast cost and sales revisions include revisions to (i) the forecasts of 2008 operating costs, other revenue and finance charges, and (ii) the customer, energy and demand forecast to incorporate the most recent key forecast assumptions. Collectively, these revisions result in an approximate 0.3 percent revenue increase in 2008 compared to that sought in the Application.

The Settlement Agreement provides for Newfoundland Power's continued use of the cash method of accounting for other post employment benefits ("OPEBs"). This results in an approximate 1.3 percent revenue decrease in 2008 compared to that sought in the Application.

The Settlement Agreement also provides for a 2008 return on common equity of 8.95 percent compared to the 10.25 percent sought in the Application. This results in an approximate 1.5 percent revenue decrease in 2008 compared to that sought in the Application.

Finally, the Settlement Agreement provides for changes to the amortizations of regulatory deferrals and reserves proposed in the Application. These changes result in an approximate 0.2 percent revenue decrease in 2008 compared to that sought in the Application.

This supplemental evidence, filed in support of the Amended Application, reviews the impacts of the revisions to the 2008 forecasts of costs and sales and the Settlement Agreement on the 2008 revenue requirement and customer electricity rates.

SECTION 2: COST AND SALES REVISIONS

2.1 Principal Revisions

The cost and sales revisions to the Application filed include revisions to:

1. ***the 2008 forecasts of operating costs, other revenue and finance charges;[5] and***
2. ***the 2008 customer, energy and demand forecast.[6]***

The overall impact of the cost and sales revisions contained in the Amended Application is to increase 2008 revenue requirement by approximately $1.5 million, which translates into an approximate 0.3 percent increase in average 2008 customer rates.

This section of the evidence reviews these principal revisions and their impact on the 2008 revenue requirement and customer electricity rates as presented in the Application.

2.2 2008 Forecasts of Operating Costs, Other Revenue and Finance Charges

The revision to the Company's 2008 operating costs forecast reflects a reduction in 2008 insurance costs of $190,000. This reduction was the result of insurance policy renewals which occurred after the filing of the Application.

The Company's 2008 forecast of other revenue has been increased by $111,000 to reflect a change in revenues associated with wheeling charges paid by Hydro. This increase reflects an

[5] The original 2008 operating cost forecast is found at pp. 13 *et. seq.* and Exhibits 1 and 2 of the Application filed on May 10, 2007. The original 2008 forecast of other revenue is found at pp. 45 *et.seq* of the Application. The original 2008 finance charges forecast is found at pp. 49 *et. seq.* of the Company Application.

[6] The original 2008 customer, energy and demand forecast is summarized at pp. 106 *et. seq.* of the Company evidence filed on May 10, 2007 and found at *Volume 2: Supporting Materials, Tab 8* of the Company Application.

increase in the rate payable by Hydro to wheel power necessary to serve its rural customers across Newfoundland Power's electrical system.[7]

The forecast of 2008 finance charges in return on rate base has been revised to reflect (i) Newfoundland Power's issue of Series AL First Mortgage Sinking Fund Bonds in August 2007[8] and (ii) a revised forecast of short term interest costs.[9] Together, these changes serve to increase the Company's 2008 forecast of finance charges by approximately $900,000.[10]

Table 2 summarizes the impact of revisions to the 2008 forecasts of operating costs, other revenue and finance charges as contained in the Amended Application.

Table 2
Cost Revision Impacts
2008 Revenue Requirement
($000s)

Operating Costs	(190)
Other Revenue	(111)[11]
Finance Charges	900
Net Revenue Requirement Impact	**599**

7 The wheeling rate was increased to reflect the higher cost of system losses associated with Hydro's wheeling requirements.

8 As authorized by Order No. P.U. 24 (2007), $70,000,000 in Series AL First Mortgage Sinking Fund Bonds (the "Series AL Bonds") was issued in August 2007 for a term of 30 years at a coupon rate of 5.901 percent. In the Application it was assumed the $60,000,000 Series AL Bonds would have a coupon rate of 5.50 percent.

9 The change in short term interest costs reflects an increase in forecast short term interest costs from 5 percent to 5.75 percent based on updated interest rate forecasts provided by the five main Canadian Chartered Banks.

10 Forecast 2008 finance charges increased in the Amended Application by approximately $1.2 million from that forecast in the Application. Approximately $900,000 of this is attributable to increased interest rates (short and long term) and the remainder is attributable to reduced cash flows which result from reductions in forecast revenue related to (i) a return on equity for ratemaking purposes of 8.95 percent (compared to 10.25 percent in the Application) and (ii) maintaining the cash basis for OPEBs accounting.

11 Increases in other revenue serve to *reduce* the amount of the Company's required revenue requirements from customer rates.

2.3 2008 Customer, Energy and Demand Forecast

Newfoundland Power's revised 2008 customer, energy and demand forecast has been revised to incorporate the most recent key forecast assumptions.

Table 3 compares the customer, energy and demand forecast contained in the Application to that contained in the Amended Application.

Table 3
2008 Customer, Energy and Demand Forecast
Comparison

	Application	**Amended Application**
Customers	233,714	234,510
% Change[12]	0.9	1.1
Energy Sales (GWh)	5,120.8	5,215.1
% Change[12]	1.3	2.0
Demand (MW)[13]	1,224	1,241
% Change[12]	1.1	1.7

The revised 2008 customer, energy and demand forecast increases Newfoundland Power's 2008 revenues and purchased power costs.

Table 4 provides a comparison of revenue and supply costs in the Application and the Amended Application.

[12] Percentage change from 2007.
[13] Native peak demand.

Table 4
Comparison of 2008 Revenue and Supply Costs
($000s)

	Application	**Amended Application**	**Difference**
Revenue from Rates	478,535	485,692	7,157
Power Supply Costs	328,786	336,819	8,033
Margin	149,749	148,873	(876)

As a result of current supply cost dynamics, the rate revenue associated with the additional customer energy requirements in 2008 will be $876,000 less than the additional power supply costs incurred to provide the additional customer energy requirements.

Table 5 shows the Company's revised customer forecast for 2007 and 2008.

Table 5
Revised Customer Forecast
2007 and 2008

	2007	**2008**
Domestic	200,935	203,197
General Service		
0-10 kW	11,897	11,903
10-100 kW (110 kVA)	8,408	8,525
110-1000 kVA	1,028	1,038
1000 kVA and Over	62	64
Total General Service	21,395	21,530
Street and Area Lighting	9,727	9,783
Total Customers	**232,057**	**234,510**

The number of customers is forecast to increase by approximately 1.1 percent between 2007 and 2008. The forecast number of customers is higher than that contained in the Application due to an increase in the housing starts forecast.[14]

Table 6 shows the Company's revised energy sales forecast for 2007 and 2008.

Table 6
Revised Energy Sales Forecast
2007 and 2008
(GWh)

	2007	**2008**
Domestic	3,063.0	3,130.8
General Service		
0-10 kW	93.0	95.8
10-100 kW (110 kVA)	633.1	647.4
110-1000 kVA	869.5	875.3
1000 kVA and Over	417.0	429.6
Total General Service	2,012.6	2,048.1
Street and Area Lighting	36.1	36.2
Total Energy Sales	**5,111.7**	**5,215.1**

Energy sales are forecast to increase by approximately 2.0 percent from 2007 to 2008.[15] The energy sales forecast is higher due to the increase in sales in the first seven months of 2007, lower electricity prices and higher personal disposable income in 2008.

Table 7 shows the Company's revised demand forecast for 2007 and 2008.

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[14] Refer to the Customer, Energy and Sales Forecast (1st Revision) filed with the Amended Application for a detailed explanation of the changes in key assumptions used in preparing the forecast.

[15] This includes 2008 elasticity effects of 17.6 GWh directly resulting from the proposed 2008 customer rate increase of 2.8 percent.

Table 7
Revised Demand Forecast
2007 and 2008
(MW)

	2007	2008
Native Peak[16]	1,220	1,241
Purchased[17]	1,102	1,123

Demand is forecast to increase by approximately 1.7 percent from 2007 to 2008. Total demand purchases from Hydro are forecast to increase by 1.9 percent from 2007 to 2008.

2.4 Summary of Costs and Sales Revision Impacts

Table 8 is a summary of the net impact of forecast revisions to the Application contained in the Amended Application on the 2008 revenue requirement.

Table 8
Application Revision Net Impacts
2008 Revenue Requirement
($000s)

Forecast Cost Revisions	599
Customer, Energy and Demand Forecast Revisions	876
Total	**1,475**

The overall impact of the cost and sales revisions to the Application, presented in the Amended Application, serves to increase 2008 revenue requirement by $1,475,000 which translates into an approximate 0.3 percent increase in average 2008 customer rates.[18]

16 Native peak is the maximum demand forecast to be served by Newfoundland Power. The 2007 native peak reflects the forecast for the winter period of December 2007 to March 2008.

17 Purchased demand is the native peak less the 117.9 MW generation credit provided for in Hydro's wholesale rate structure.

18 $1,475,000 divided by $485,692,000 (existing 2008 forecast revenue) is 0.30 percent.

SECTION 3: THE SETTLEMENT AGREEMENT

3.1 The Settlement Agreement

The Settlement Agreement, if approved by the Board, has material impacts upon Newfoundland Power's 2008 revenue requirement as presented in the Application.

The primary impacts of the Settlement Agreement upon Newfoundland Power's 2008 revenue requirement relate to:

1. ***the 2008 employee future benefits costs;***
2. ***the 2008 cost of capital; and***
3. ***the amortization of regulatory deferrals and reserves.***

The overall impact of the Settlement Agreement is to reduce the average rate increase sought in the Application by approximately 3 percent.[19]

This section of the evidence reviews the Settlement Agreement and its impact on 2008 revenue requirement and customer electricity rates.

3.2 Employee Future Benefits

The Settlement Agreement provides for continued recognition of OPEBs on a cash basis and the adoption of accrual accounting for income tax associated with pension costs.

[19] This is composed of a reduction of approximately 1.3 percent related to OPEBs accounting, approximately 1.5 percent related to return, and approximately 0.2 percent related to amortizations.

Table 9 compares the impacts of employee future benefits on the forecast 2008 revenue requirement reflected in the Application and the 2008 revised revenue requirement reflected in the Amended Application.

Table 9
Employee Future Benefits Proposals
Forecast 2008 Revenue Requirement
($ millions)

	Application[20]	**Amended Application**
OPEBs Accrual Method	9.4	-
Tax-Effects		
OPEBs	(3.0)	-[21]
Pensions	0.8	0.8
Increase in Revenue Requirement	**7.2**	**0.8**
Increase in Revenue Requirement (%)	**1.5**[22]	**0.2**[23]

Table 9 shows that the employee future benefits provisions of the Settlement Agreement reduces revenue requirement by approximately $6.4 million or 1.3 percent [24] compared to that sought in the Application.[25]

Newfoundland Power's next general rate application is currently expected to be filed in 2010 to establish customer rates for 2011.

20 See (i) Table 9 on page 12 of the *A Report on Employee Future Benefits* found at *Tab 4* in *Volume 2: Supporting Materials* of the Application (the "OPEBs Report") and (ii) Table 32 on page 81 of the Application.
21 Under the cash method of accounting for OPEBs expense, tax-effecting would have no impact on the amount of income tax expense that is recognized.
22 $7,200,000 divided by $485,692,000 (existing 2008 forecast revenue) equals 1.48%.
23 $800,000 divided by $485,692,000 (existing 2008 forecast revenue) equals 0.16%.
24 1.5 percent as per the Application minus 0.2 percent as per the Amended Application equals 1.3 percent.
25 $7.2 million less $0.8 million equals $6.4 million.

Table 10 compares the estimated impact on: (i) 2011 revenue requirement of adopting the accrual method of accounting for OPEBs, with tax-effecting as proposed in the Application in 2011; and (ii) the associated transitional obligation resulting from Newfoundland Power's maintaining the cash basis of accounting for OPEBs until 2011.[26]

Table 10
OPEBs Accrual Method
Adoption in 2011 vs. 2008
($ millions)

	2008	**2011**
Revenue Requirement		
OPEBs Accrual Method[27]	9.4	9.2
Tax-Effecting	(3.0)	(2.9)
Increase in Revenue Requirement	**6.4**	**6.3**
Transitional Obligation	**34.1**	**52.9**

Table 10 shows that the estimated increase in annual revenue requirements associated with *adopting* the accrual method of accounting for OPEBs, with tax-effecting, would not be materially impacted by addressing the matter in 2011 rather than in 2008.

The principal impact of delaying consideration of adopting the accrual method of accounting for OPEBs is that the transitional obligation will increase by approximately $6.3 million per year. It is forecast that the transitional obligation will increase to $52.9 million in 2011 from $34.1 million in 2008.

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[26] Estimated based on the OPEBs actuarial valuation dated January 17, 2007 (found at *Tab 5 in Volume 2: Supporting Materials* of the Application) and a weighted average cost of capital of 8.37 percent (see Exhibit 5.1 (1st Revision), page 6 of 8, October 11, 2007). Assumes 2011 will be the year of Newfoundland Power's next general rate application.

[27] The slight decrease in revenue requirement from $9,400,000 in 2008 to $9,200,000 in 2011 is due to a decrease in the Company's statutory income tax rate from 34.5 percent to 32.5 percent.

The impact of the recovery of the transitional obligation on customer rates will only be determinable at the time the matter is addressed. A key determinant of the customer rate impact will be the period over which the Board authorizes recovery of the transitional obligation.[28]

Both the cash method and accrual method of accounting for OPEBs are currently consistent with Canadian Generally Accepted Accounting Principles.[29] Both methods are also reasonably consistent with current Canadian regulatory practice, particularly for investor-owned utilities.[30]

The choice of accounting methods for OPEBs does not impact the aggregate amount of OPEBs liabilities to be recognized or recovered as part of the cost of service. Accordingly, the principal issue related to OPEBs from a cost of service perspective relates to the *timing* of recognition, or recovery from customers, of Newfoundland Power's OPEBs liabilities.[31]

In the context of the regulatory principles of intergenerational equity and rate stability, the choice of accounting method for OPEBs necessarily requires consideration of the appropriate weight to be

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[28] The following table illustrates *pro forma* customer rate impacts for cost recovery of the transitional obligation over a range of periods of amortization.

***Pro forma* Cost Recovery**
of Transitional Obligation
(with tax-effecting, based on 2008 Forecast Revenue)

	2008	**2011**
Transitional Obligation ($ millions)	**34.1**	**52.9**
Cost Recovery (percent of revenues)		
5-year Amortization	1.4	2.1
10-year Amortization	0.7	1.0
15-year Amortization	0.5	0.7

[29] See (i) pages 7 and 8 of Grant Thornton's report on Newfoundland Power's 2003 general rate application, (ii) page 8 of Grant Thornton's report on the Application (iii) page 3 of *A Report on Employee Future Benefits* found at *Tab 4* in *Volume 2* and (iv) pages 82 and 83 of Order No. P.U. 19 (2003).

[30] Of 24 Canadian utilities surveyed, 18 use the accrual method and 6 use the cash method. See page 4 of the Report on Employee Future Benefits. However, of the 13 Canadian utilities which are investor-owned (as opposed to provincially or municipally owned), 7 use the accrual method and 6 use the cash method.

[31] See Newfoundland Power's responses to Requests for Information Nos. CA-NP-201 and CA-NP-204.

applied to each principle at a point in time. The need to weigh, and strike a balance between, the principles of intergenerational equity and rate stability in this regard was recognized by the Board in Order No. P.U. 19 (2003)[32] and has been recognized by other regulators.[33]

Table 11 shows electricity price changes for Newfoundland Power customers in the period from 2002 to January 1, 2008 should the Board approve the Amended Application.

Table 11
Rate Changes: 2002 to 2008F
(percent)

	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008F**	**Total[34]**
Newfoundland Power	-0.6	-0.2	-	-0.5	-	-0.5	2.8	1.0
Newfoundland Hydro	3.7	-	5.3	-	-	3.1	-	12.6
RSP/RSA/MTA	-0.1	2.0	4.5	5.2	4.8	-5.3	-	11.1

Table 11 shows that to January 1, 2008, customer rates will have increased by approximately 26 percent on a compound basis over a 6-year period, principally because of the significant increases in the price of fuel burned at Hydro's Holyrood thermal generating station.

The rate increases experienced by customers over this period have influenced the consensus regarding continued recognition of OPEBs on a cash basis reflected in the Settlement Agreement.

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32 At page 83, the Board stated: *In addressing the question of whether NP's treatment of employee future benefits for rate setting purposes is consistent with established regulatory practice, Mr. Browne concludes at page 13 of his report that: From the perspective of the principle of intergenerational equity, the accrual method for recovering OFEB costs is preferable to the pay-as-you-go method proposed by NP. However, the NP proposal (to retain the cash method of accounting) is a practical approach that recognizes the (rate) impact of dealing with the transition from one method to another." "To avoid rate impact on consumers, the Board is prepared to accept NP's proposal to continue with using the cash basis for recognizing expenses for other employee future benefits."*

33 Examples include decisions by the British Columbia Utilities Commission pertaining to (i) BC Gas, (ii) Pacific Northern Gas Limited, (iii) Aquila Networks Canada (British Columbia) Ltd. and (iv) BC Hydro; and a decision by the Ontario Energy Board pertaining to Union Gas. See pp. 4, 5 and 10 of *Regulatory Accounting Issues Related to 2007 Rate Application*, May 4, 2007, *Volume 3: Expert Evidence*.

34 The total reflects the *compounded* change in rates from 2002 to 2008.

The Amended Application seeks an approximate 1.8 percent increase in 2008 revenues for depreciation cost recovery. This increase is principally due to the 2005 conclusion of the reserve variance true-up.[35] In addition, the adoption of accrual accounting for income tax associated with pension costs agreed to in the Settlement Agreement accounts for an approximate 0.2 percent increase in 2008 revenues.[36]

The adoption of accrual accounting for OPEBs in 2008 as requested in the Application would clearly improve Newfoundland Power's overall recovery of current costs in current rates. However, approximately 70 percent of the 2.8 percent revenue increase proposed in the Amended Application[37] will result in improved overall 2008 cost recovery when compared to the *status quo*. Accordingly, if approved by the Board, the Amended Application will mark meaningful progress in better matching Newfoundland Power's current costs and revenues.

3.3 Cost of Capital

3.3.1 Rate of Return on Common Equity

The Settlement Agreement provides for a rate of return on common equity of 8.95 percent for ratemaking purposes in 2008[38] and a capital structure consistent with that proposed in the

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35 See pages 7-8, 43, and 68-73 of the Application.

36 The adoption of accrual accounting for income tax associated with pension costs, in effect, provides for more complete *current* recovery of pension costs in customer rates. While the degree of improved cost recovery this provides is obviously less than that proposed in the Application, it does mark some progress in improving current recovery of *overall* employee future benefit costs (i.e., pension costs and other OPEBs costs).

37 2.0 percent (1.8 percent depreciation plus 0.2 percent accrual income tax accounting for pensions) divided by 2.8 percent (total proposed 2008 average rate increase) equals 0.71.

38 Refer to Exhibit 10 (1st Revision) for Newfoundland Power's proposed rate of return on rate base in 2008.

Application. A rate of return on common equity of 8.95 percent reduces revenue requirement in 2008 by approximately $7.3 million or 1.5 percent compared to that sought in the Application.[39]

The ability to maintain sound financial credit metrics is a key component in ensuring an investment grade credit rating for Newfoundland Power. The Company's cash flows and financial credit metrics in 2008 are impacted by the Settlement Agreement primarily due to the reduction in the return on common equity to 8.95 percent and the recognition of OPEBs on the cash basis versus the accrual basis.[40]

Newfoundland Power's forecast 2008 credit metrics based on a rate of return on common equity of 8.95 percent and the continued recognition of OPEBs on the cash basis are provided in Table 12.[41]

Table 12
Forecast 2008 Credit Metrics

Pre-tax Interest Coverage (times)	2.5
Cash Flow Interest Coverage (times)	2.9
Cash Flow Debt Coverage (percent)	14.9

Table 12 shows that the Company's forecast credit metrics in 2008 are marginally below the bottom of the range recommended by Moody's Investor Services necessary to maintain its investment grade credit rating.[42]

[39] 10.25 percent minus 8.95 percent (The Settlement Agreement) equals 1.30 percent. 1.30 percent times $365,341,000 (2008 average book equity in the Amended Application) equals $4,749,000. $4,749,000 divided by 0.655 (1 – tax rate) equals $7,251,000. $7,251,000 divided by $485,692,000 (existing 2008 forecast revenue) equals 1.49 percent.

[40] Refer to page 58 *et. seq.* and Table 25 of the Company's evidence for the impact of the adoption of accrual accounting for OPEBs on cash flow and financial credit metrics.

[41] This is revised from Table 25 as filed in the Company's evidence.

[42] In order to maintain the Company's investment grade credit rating, Moody's requires a cash flow interest coverage of 3.0 times or higher and a cash flow debt coverage of 15 percent or higher. See page 3 of Moody's Investor Services credit opinion contained in Exhibit 6.

Exhibit 7 (1st Revision) shows the relationship between the Company's capital structure, the rate of return on common equity and financial credit metrics on a *pro forma* 2008 basis.

3.3.2 The Automatic Adjustment Formula

The Settlement Agreement provides for the following changes to the Formula: (i) that the risk-free rate for 2008 be set at 4.60 percent and the risk premium be set at 4.35 percent; and (ii) that the arithmetic expression of the formula be changed to reflect the transition to the Asset Rate Base Method ("ARBM") of calculating rate base.

Beyond 2008, the Formula will continue to establish a forward-looking risk free rate for an ensuing year by averaging the daily *ask yields* for the three most recent series of long-term Government of Canada bonds for the last five trading days in October and the first five trading days in November.

3.4 Regulatory Deferrals and Reserves

The Settlement Agreement provides for a 3-year amortization of the Regulatory Deferrals and the December 31, 2006 balance in the Purchased Power Unit Cost Variance Reserve (the "Unit Cost Reserve") as compared to a 5-year amortization period proposed in the Application.

Table 13 shows the 2008 revenue requirement impacts of a 3-year amortization of the Regulatory Deferrals and the Unit Cost Reserve resulting from the Settlement Agreement.[43]

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[43] This is an amendment to Table 34 as filed in the Company's evidence.

Table 13
Amortization of Regulatory Deferrals and Unit Cost Reserve
***Pro forma* 2008 Revenue Requirement Impact**
2008 to 2010
($000s)

	2008	2009	2010
Revenue Deferrals			
2005 Unbilled Revenue[44]	(11,008)	(7,050)	(7,050)
Municipal Tax Liability	(1,362)	(1,362)	(1,362)
Cost Recovery Deferrals			
Depreciation	5,896	5,896	5,896
Replacement Energy	598	598	598
Unit Cost Reserve	(688)	(688)	(688)
Revenue Requirement Impacts	**(6,564)**	**(2,606)**	**(2,606)**

The 3-year amortization of Regulatory Deferrals and the Unit Cost Reserve agreed to in the Settlement Agreement and sought in the Amended Application will reduce 2008 revenue requirement by approximately $6.6 million. This compares to a reduction in 2008 revenue requirement of $5.5 million sought in the Application.[45] The difference of approximately $1 million represents a decrease of approximately 0.2 percent [46] in 2008 revenue requirement.[47]

[44] The 2005 Unbilled Revenue amortization in 2008 includes $2,592,000 related to the 2005 tax settlement and $4,618,000 related to the amortization of the 2005 Unbilled Revenue remaining balance. The 2008 revenue requirement impact is calculated as (($2,592,000 plus $4,618,000) divided by 0.655 (1-tax rate) equals $11,008,000).

[45] Refer to Tables 34 and 36 filed in the Company's evidence. In these tables, a total of $5,521,000 in *pro forma* net revenue requirement decreases were indicated on account of Regulatory Deferrals and the Unit Cost Reserve ($5,108,000 in Table 34 and $413,000 in Table 36).

[46] $6,564,000 (Table 13, page 19) minus $5,521,000 (Revenue requirement impact of 5-year amortization of revenue accrual and cost deferral minus unit cost reserve variance from the Application) divided by $485,692,000 equals 0.2 percent.

[47] $1,043,000 divided by $485,692,000 equals 0.21 percent.

3.5 Summary of Settlement Agreement Impacts

Table 14 summarizes the impact of the Settlement Agreement on the 2008 revenue requirement as contained in the Amended Application.

Table 14
Settlement Agreement Impacts
2008 Revenue Requirement[48]
($000s)

OPEBs	(6,327)
Cost of Capital	(7,251)
Regulatory Deferrals and Amortizations	(1,043)
Net Impact	**(14,621)**

The overall impact of the Settlement Agreement presented in the Amended Application, is to decrease the 2008 revenue requirement by approximately $14,600,000 which translates into an approximate 3 percent decrease in average 2008 customer rates[49] from that sought in the Application.

[48] The actual impact on revenue requirement will vary slightly due to the effects of changes on rate base.
[49] $14,621,000 divided by $485,692,000 (2008 forecast existing revenue) is 3 percent.

SECTION 4: 2008 REVISED REVENUE REQUIREMENT

4.1 Summary of 2008 Revised Revenue Requirement

The 2008 revised revenue requirement in the Amended Application is forecast to be approximately $506.8 million which is offset by revenue deferral amortizations of approximately $8.6 million.

The increase in revenue required from customer rates in 2008 will result in an average increase in current customer rates of 2.8 percent.

Exhibit 9 (1st Revision) presents the forecast 2008 revised revenue requirement.[50] Exhibit 5.1 presents the 2008 forecast financial performance reflecting the Amended Application.

[50] The exhibit compares the 2008 forecast revenue requirement using existing rates and the revenue requirement proposed in this proceeding.

4.2 2008 Revised Revenue Requirement

Table 15 shows a summary of the 2008 revised revenue requirement including the revenue required to be recovered from customer rates.[51]

Table 15
Summary of 2008 Revised Revenue Requirement
($000s)

Power Supply Cost	337,159
Operating Costs	47,700
Employee Future Benefits	3,348
Depreciation & Related Amortization	44,070
Income Taxes	19,568
Return on Rate Base	67,966
Other Adjustments[52]	92
	519,903
Deductions:	
Other Revenue	(12,122)
Non-Regulated Expenses (Net of Tax)	(983)
Proposed 2008 Revenue Requirement	**506,798**
Revenue Deferral Amortization	(8,572)
Proposed 2008 Revenue Requirement from Rates	**498,226**

[51] This is an amendment to Table 41 as filed in the Company's evidence.
[52] Composed of $62,000 related to the amortization of Capital Stock issue expenses and $30,000 related to interest on customer deposits.

Costs

Table 16 shows forecast 2008 power supply cost.[53]

Table 16
2008 Power Supply Cost
($000s)

Existing	336,819
Amortizations	
Weather Normalization Reserve	2,076 [54]
Replacement Energy Cost	598 [55]
Unit Cost Reserve	(688) [56]
Impact of Elasticity	(1,646)
Proposed	**337,159**

Table 17 shows forecast 2008 operating costs.[57]

Table 17
2008 Operating Costs
($000s)

Existing	48,533
Application Costs Amortization	(833) [58]
Increased OPEBs Costs	- [59]
Pension and ERP Costs	3,348
Proposed	**51,048**

Exhibit 1 (1st Revision) and Exhibit 2 (1st Revision) show the proposed forecast operating costs for 2008 by function and breakdown respectively.

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[53] This is an amendment to Table 42 as filed in the Company's evidence.
[54] The Settlement Agreement provides for a 5-year amortization of the Degree Day component of the Weather Normalization Reserve.
[55] The Settlement Agreement provides for a 3-year amortization of Replacement Energy Costs.
[56] The Settlement Agreement provides for a 3-year amortization of Unit Cost Reserve.
[57] This is an amendment to Table 43 as filed in the Company's evidence.
[58] The Settlement Agreement provides for a 3-year amortization of Application and hearing costs related to the 2008 general rate application.
[59] The Settlement Agreement provides for the continued recognition of OPEBs costs on the cash basis of accounting.

Table 18 shows forecast 2008 depreciation and related amortizations.[60]

Table 18
2008 Depreciation Cost and Related Amortization
($000s)

Existing Depreciation	41,002
Proposed Depreciation Rates	(620)[61]
Amortization Reserve Variance	(174)[62]
Proposed Depreciation	**40,208**
Amortization of Cost Recovery Deferral	**3,862** [63]

Table 19 shows forecast 2008 income taxes.[64]

Table 19
2008 Income Taxes
($000s)

Existing	13,841
Tax Effects of Application Proposals	5,727
Proposed	19,568

Return on Rate Base

Exhibit 8 (1st Revision) shows the forecast 2008 average rate base. Exhibit 10 (1st Revision) shows the forecast 2008 return on rate base and rate of return on rate base.

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[60] This is an amendment to Table 44 as filed in the Company's evidence.
[61] The Settlement Agreement provides for the implementation of revised depreciation rates based on the 2006 Depreciation Study to be effective January 1, 2008.
[62] The Settlement Agreement provides for a 4 year amortization of a $0.7 million depreciation reserve variance resulting from the 2006 Depreciation Study beginning in 2008.
[63] The Settlement Agreement provides for a 3 year amortization of deferred cost recoveries related to deferred depreciation costs beginning in 2008.
[64] This is an amendment to Table 45 as filed in the Company's evidence.

Table 20 summarizes the forecast 2008 return on rate base and rate of return on rate base.[65]

Table 20
2008 Rate of Return on Rate Base
($000s)

Forecast Average Rate Base	812,212
Forecast Regulated Returns	
Debt	34,680
Preferred Equity	586
Common Equity	32,700
Return on Rate Base	**67,966**
Rate of Return on Rate Base (%)	**8.37**[66]

As a result of the Company's completion of the transition to the ARBM, the Company's weighted average cost of capital will be the same as the rate of return on rate base for ratemaking purposes.

Deductions and Revenue Amortizations

Exhibit 9 (1st Revision) shows the forecast 2008 deductions from 2008 revised revenue requirement.

[65] This is an amendment to Table 46 as filed in the Company's evidence.

[66] The rate of return on rate base is calculated as ($67,966,000 divided by $812,212,000) equals 8.37 percent. The range of return on rate base proposed in the Amended Application for 2008 is 8.19 to 8.55 percent based upon a 36 basis point range as approved by the Board in Order Nos. P.U. 36 (1998-99) and P.U. 19 (2003).

Table 21 summarizes the forecast 2008 deductions from revenue requirement.[67]

Table 21
2008 Proposed Deductions
($000s)

Other Revenue	12,122[68]
Non-Regulated Expenses	983[69]
Proposed	**13,105**

Table 22 summarizes the forecast 2008 revenue deferral amortizations.[70]

Table 22
2008 Proposed Amortizations
Revenue Deferrals
($000s)

2005 Unbilled Revenue	7,210[71]
Municipal Tax Liability	1,362[72]
Revenue Amortization	**8,572**

4.3 Required Revenue Increase

Table 23 shows the forecast increase in revenue from rates of $14.0 million required to meet the Company's proposed 2008 revenue requirement based on its Amended Application.[73]

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67 This is an amendment to Table 47 as filed in the Company's evidence.

68 $11,083,000 (existing other revenue in the Amended Application) plus $1,200,000 (interest revenue) plus $30,000 (regulation changes; see *Section 4.5 Changes to the Rules and Regulations from the Application*) minus $191,000 (interest on rate stabilization account from the Amended Application).

69 Non-regulated expenses are those expenses incurred by the Company that are not recoverable through rates under Section 80 (2) of the *Public Utilities Act*. Non-regulated expenses, net of applicable income taxes, are estimated and deducted from revenue requirements in accordance with Board Orders. See Order No. P.U. 7 (1996-97).

70 This is an amendment to Table 48 as filed in the Company's evidence.

71 The 2005 Unbilled Revenue amortization for 2008 in the Amended Application includes $2,592,000 related to the 2005 tax settlement and $4,618,000 related to the 3-year amortization of the 2005 Unbilled Revenue as provided for in the Settlement Agreement.

72 The Settlement Agreement provides for a 3 year amortization of the Municipal Tax Liability beginning in 2008. The Company's proposals regarding the municipal tax liability was reviewed in *Section 3.7.1 Regulatory Deferrals* of its evidence.

73 This is an amendment to Table 49 as filed in the Company's evidence.

Table 23
2008 Required Revenue Increase
($000s)

2008 Proposed Revenue Requirement	506,798[74]
Revenue From Existing Rates	(485,692)
Amortization of Revenue Deferrals	(8,572)
Elasticity Impact	1,460[75]
Required Increase in Revenue from Rates	**13,994**

The increase in revenue from rates for 2008 requires an average increase in current customer rates of 2.8 percent effective January 1, 2008. Exhibit 11 (1st Revision) is the detailed calculation of the 2008 average rate increase.

[74] 2008 proposed revenue requirement net of other revenue and non-regulated expenses of $13,105,000.

[75] Elasticity impact is lower than the elasticity impact shown in power supply cost due to the effect of current energy cost dynamics on the Island interconnected grid.

SECTION 5: CUSTOMER RATES & REGULATIONS

5.1 2008 Customer Rates

An average increase of 2.8 percent in customer rates is required to provide the proposed 2008 test year revenue requirement.

This section of the evidence reviews the proposed rate change plan, rate design proposals and the customer impacts of the proposed 2008 test year revenue requirement.

5.2 Rate Change Plan

Newfoundland Power proposes to bring all customer classes within its target revenue to cost ratio range at its next general rate proceeding. The rates proposals in the Amended Application, if approved by the Board, will advance approximately half way to this goal.

Table 24 provides the 2008 proposed rate changes and relative rate changes for each class.

Table 24
Proposed Rate Changes by Class

Rate	Class	Proposed Rate Change	Relative to Average
1.1	Domestic	3.9%	1.1% above[76]
2.1	General Service 0-10 kW	(1.2%)	4% below
2.2	General Service 10-100 kW (110 kVA)	(0.2%)	3% below
2.3	General Service 110-1000 kVA	1.8%	1% below
2.4	General Service 1000 kVA and Over	2.8%	Average
4.1	Street and Area Lighting	2.8%	Average

[76] The Domestic class increase relative to average is slightly greater than 1 percent to ensure matching of revenue from rates to revenue requirement. The Domestic class is used to ensure matching since it is the largest class, and such reconciling adjustments will have the least impact on the Domestic class.

5.3 Rate Design Proposals

The following is a summary of the Company's rate design proposals. These proposals have been modified from the Application to recognize that a decrease in rates is proposed for Rate 2.1 in the Amended Application.

- With the exception of Rate 2.1, energy charges should increase to better reflect the high marginal cost of energy on the system.
- No increase is proposed in the Basic Customer Charges so as to accommodate changes to the energy charges to better reflect the marginal cost of energy on the system.
- It is proposed that the energy charge be decreased in Rate 2.1 because the revenue requirement from this class is proposed to decrease and the current energy charge exceeds both the embedded and the marginal costs.[77]
- The demand charges during the non-winter season should be reduced to increase the price differential between the winter and non-winter season to better reflect the seasonal cost differences on the system.
- The energy component of the maximum monthly charge in the General Service Rates 2.2, 2.3 and 2.4 should be increased to reflect the overall average increase in rates of 2.8 percent.
- The street and area lighting rates should continue to be developed based on recovering embedded costs with the price of fixtures, poles and wiring varying in a manner reflective of differences in their fixed costs and variable operating costs.
- The Curtailable Service Option provides operational and planning benefits and should be maintained. It is proposed that the annual credit remain at $29 per kVA and the value of curtailable load on the system continue to be monitored.

[77] This proposal is consistent with the Settlement Agreement.

5.4 Customer Impacts

Customer class impacts, from a percent billed basis, will vary according to usage. This is because individual rate components within each rate are proposed to change by different percentages, with tail block energy charges receiving the highest increases. The general impacts are as follows:

- Domestic customers with higher energy usage will receive higher percent rate increases.
- General Service customers served under Rate 2.1 will experience either no increase in rates or a decrease in rates.
- General Service customers served under Rates 2.2, 2.3 and 2.4 will experience percentage impacts that vary by load factor, with higher load factor customers (high energy use relative to billing demand) experiencing higher percentage increases. Low load factor customers served under Rates 2.2, 2.3 and 2.4 that are charged under the maximum monthly charge, will experience percentage increases approximately equal to the overall proposed average rate increase.

Exhibit 11.1 is a detailed summary of the impacts by customer class.

5.5 Rate Stabilization Clause

The Settlement Agreement provides for modification of the Rate Stabilization Clause to ensure recovery of prudently incurred energy supply costs related to the cost of production at Hydro's Holyrood Thermal Generating Station.[78]

[78] *Section 3.8.1 Supply Cost Dynamics* of the Application describes the need for a mechanism to ensure recovery of prudently incurred energy supply costs related to the cost of production at Holyrood.

Regulatory mechanisms have been established by the Board to provide for the efficient regulation of Newfoundland Power's returns and its costs of providing service. Regulatory mechanisms that permit recovery of supply costs for Canadian regulated distribution companies are common regulatory practice.[79] The Board's approval of the Energy Supply Cost Variance clause in the RSA is reasonable in that it would permit Newfoundland Power to recover prudently incurred energy supply costs that are beyond its control.

The Settlement Agreement also provides for the Energy Supply Cost Variance clause to apply to the end of 2010 with any renewal or extension requiring further consideration by the Board. This provision will ensure reasonable and timely Board oversight for the Energy Supply Cost Variance clause.

Exhibit 12 (1st Revision) is the proposed Rate Stabilization Clause.

5.6 Retail Rate Review

Attachment A of the Settlement Agreement provides a framework for a review of Newfoundland Power's rate designs (the "Rate Review"). Assessing retail rate design is a complex matter. The Rate Review provides an opportunity for a comprehensive review of the retail rate design issues separately from a General Rate Application which should result in improved process efficiency in dealing with the complex issues involved.[80]

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[79] Attachment A to the response to CA-NP-444 provides an overview of current supply cost recovery practices for regulated investor-owned distribution utilities in Canada together with details of the regulatory mechanisms.

[80] At the 2006 Hydro general rate proceeding, the Board approved dealing with a review of the depreciation methodology through a separate process from the general rate application. The separate review was proposed by intervenors due the complexity of the depreciation issue and to provide for regulatory efficiency.

The Rate Review includes a review of existing and alternative rate designs with the objective to provide increased emphasis on energy efficiency and conservation in customer rate designs. Designing rates to promote energy efficiency involves balancing the desire for rates to provide the right signals to customers with the need to have rates that customers can understand, and to which they can respond.[81] In modifying rate structures to promote energy efficiency, the cost impact on customers is one of a number of policy considerations.[82] Participation of all interested stakeholders is desirable when considering material changes to customer rate structures.

The Rate Review should provide greater transparency in the consideration of rate design alternatives for Newfoundland Power's customers.

[81] *National Action Plan for Energy Efficiency* (United States), July 2006, Chapter 5, Rate Design, page 5-5.

[82] A May 2006 report, prepared by NERA Economic Consulting for the Edison Electric Institute (EEI), identified a number of policy issues for regulators to consider regarding time-based rate designs. These include:

- Are the existing rates sending the right price signals to customers?
- What form(s) of time-based rate design should be used?
- What rate structure changes would be acceptable to customers?
- Should time-based rate structures be optional?
- How should an interruptible/curtailable rate be priced and is this form of rate reliable enough to avoid the need for costly new generation resources?
- How should time-based rate designs be implemented to gain customer acceptability?