Newfoundland Power Inc.

55 Kenmount Road
PO Box 8910
St. John's, Newfoundland
A1B 3P6
Business: (709) 737-5600
Facsimile: (709) 737-2974
www.newfoundlandpower.com

DELIVERED BY HAND

May 28, 2009

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: 2010 General Rate Application

Forwarded with this letter are the original and 8 copies of a general rate application for a review of Newfoundland Power's 2010 costs and customer rates (the "2010 General Rate Application").

The 2010 General Rate Application and prefiled supporting materials have been provided in two volumes set out as follows:

Volume 1: Application, Company Evidence and Exhibits

Volume 2: Supporting Materials

It is the Company's intention to file an Adobe portable document format (pdf) copy of this filing within the next few days. Additional copies of the filing will be made available as required.

The Company will post a copy of the 2010 General Rate Application on its website at www.newfoundlandpower.com. In addition, copies will be available at the Company's offices in Stephenville, Corner Brook, Grand Falls-Windsor, Gander, Clarenville, Burin, Carbonear, and St. John's.

The average increase to customers' bills proposed in the 2010 General Rate Application is 6.1%. This increase is based upon the rate stabilization and municipal tax adjustments ("RSA/MTA adjustments") ***currently*** in effect.

The Company is filing an application regarding RSA/MTA adjustments for July 1, 2009 contemporaneously with the filing of the 2010 General Rate Application. We would expect to update the 2010 General Rate Application to reflect the Board's order regarding the RSA/MTA adjustments in due course, and in any event prior to the Board's consideration of the 2010 General Rate Application.

We trust the foregoing and enclosed are found to be in order. However, please feel free to contact the undersigned if you have any questions.

Yours very truly,

Peter Alteen
Vice President, Regulatory Affairs
& General Counsel

Enclosures

c. Geoffrey Young (4 copies)
Newfoundland and Labrador Hydro

Thomas Johnson (5 copies)
Consumer Advocate

Application, Company Evidence and Exhibits

A Note on Financial Presentation

In the normal course of its business, Newfoundland Power incurs costs that are not recognized as operating costs recoverable in customer rates. These include certain inter-affiliate charges, certain elements of executive compensation, charitable donations and promotional expenses.

For clarity of presentation and analysis, Newfoundland Power has excluded these costs in the presentation of both actual and forecast operating costs in this Application. This is consistent with the fact the costs are not recoverable in customer rates and therefore are not included in the determination of the Company's revenue requirements.

While these non-regulated costs are not included for ratemaking purposes, they are required by accounting standards to be recognized by the Company for financial statement purposes. Accordingly, in Exhibits 3 and 11, which contain actual and forecast financial statements of Newfoundland Power, these costs (and tax effects associated with them) are included.

VOLUME 1: APPLICATION AND COMPANY EVIDENCE

A. APPLICATION

B. COMPANY EVIDENCE

SECTION 1 INTRODUCTION

Page

SECTION 2 CUSTOMER OPERATIONS

SECTION 3 FINANCE

SECTION 3 FINANCE (Cont'd) **Page**

SECTION 4 2010 RATE BASE & REVENUE REQUIREMENTS

SECTION 5 CUSTOMER RATES

C. EXHIBITS

Exhibit 1	Operating Costs by Function: 2007 to 2010F
Exhibit 2	Operating Costs by Breakdown: 2007 to 2010F
Exhibit 3	Financial Performance: 2007 to 2010E
Exhibit 4	Credit Rating Reports: DBRS and Moody's
Exhibit 5	2010 Credit Metrics
Exhibit 6	2010 Forecast Average Rate Base
Exhibit 7	2010 Revenue Requirements
Exhibit 8	2010 Forecast Capital Structure and Return on Rate Base
Exhibit 9	Pension Expense Variance Deferral Account
Exhibit 10	2010 Average Rate Change
Exhibit 11	2010 Comparative Financial Forecasts: Existing vs. Proposed
Exhibit 12	Summary of Existing and Proposed Customer Rates

VOLUME 2: SUPPORTING MATERIALS

1. Labour Forecast 2009 - 2010
2. 2010 Rate Base Allowances
3. 2008 Pension Valuation
4. Report on Other Post Employment Benefits
5. Actuarial Valuation of OPEBs
6. Customer, Energy and Demand Forecast
7. Cost of Service Study
8. Demand Management Incentive Account
9. Energy Supply Cost Variance
10. Opinion on Capital Structure and Fair Return on Equity

IN THE MATTER OF the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47, as amended, (the "Act"); and

IN THE MATTER OF a general rate application (the "Application") by Newfoundland Power Inc. ("Newfoundland Power") to establish customer electricity rates for 2010.

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power **SAYS THAT**:

A. Background:

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. The Act provides that the Board has the general supervision of public utilities and requires that a public utility, in effect, submit for the approval of the Board the rates, tolls and charges for the service provided by the public utility and the rules and regulations which relate to that service.

3. By Order Nos. P.U. 16 (1998-99), P.U. 36 (1998-99) and P.U. 19 (2003), the Board ordered, in effect, that an automatic adjustment formula be established to set the electrical rates and allowed rates of return for Newfoundland Power based upon changes in long term Government of Canada bond yields (the "Formula").

4. By Order No. P.U. 32 (2007), the Board ordered, amongst other things, that:

   (a) the Formula be used to establish the rate of return on rate base for Newfoundland Power for three years subsequent to 2008 unless otherwise directed by the Board;

   (b) Newfoundland Power continue recognition of other post employment benefits expenses on a cash basis;

   (c) Newfoundland Power recover energy supply cost variances through its Rate Stabilization Account through the end of 2010 (the "Energy Supply Cost Variance clause");

   (d) Newfoundland Power establish a Demand Management Incentive Account; and

   (e) Newfoundland Power file its next depreciation study relating to plant in service as of December 31, 2010.

5. By Order No. P.U. 13 (2009), the Board approved the creation of a Conservation Cost Deferral Account to provide for the deferred recovery, until a further Order of the Board, of 2009 costs related to the implementation of a Five-Year Energy Conservation Plan (the "Conservation Plan").

6. Since 2007, changes in financial markets, changes in Newfoundland Power's cost of service, and developments in accounting practice and standards have occurred, all as set out in the evidence filed in support of the Application.

B. Newfoundland Power Proposals:

7. Newfoundland Power proposes that the Board discontinue use of the Formula for setting the allowed rate of return on rate base for Newfoundland Power as set out in the evidence filed in support of the Application.

8. Newfoundland Power proposes that the Board approve, with effect from January 1, 2010, the adoption of the accrual method of accounting for other post employment benefits and for income tax related to other post employment benefits as set out in the evidence filed in support of the Application.

9. Newfoundland Power proposes that the Board approve, with effect from January 1, 2010, the Pension Expense Variance Deferral Account as set out in the evidence filed in support of the Application.

10. Newfoundland Power proposes that the Board approve amortizations, with effect from January 1, 2010, to:

    (a) amortize the recovery over a four year period of certain 2009 conservation costs associated with implementation of the Conservation Plan; and

    (b) recover over one year an estimated $750,000 in Board and Consumer Advocate costs related to the Application;

    as set out in the evidence filed in support of the Application.

11. Newfoundland Power proposes that the Board approve that the next depreciation study relate to plant in service as of December 31, 2009 as set out in the evidence filed in support of the Application.

12. Newfoundland Power proposes that the Board approve continued use of the Energy Supply Cost Variance clause beyond 2010, and the Demand Management Incentive Account until further Order of the Board.

13. Newfoundland Power proposes that the Board approve an overall average increase in current customer rates of 6.1 percent, with effect from January 1, 2010, based upon:

(a) a forecast average rate base for 2010 of $867,396,000;

(b) a rate of return on average rate base for 2010 of 9.15 percent in a range of 8.97 percent to 9.33 percent; and

(c) a forecast revenue requirement for 2010 of $545,312,000 to be recovered from electrical rates;

as set out in the evidence filed in support of the Application.

14. Newfoundland Power proposes that the Board approve rates, tolls and charges effective for service provided on and after January 1, 2010, which result in average increases in current customer rates by class as follows:

Rate Class	***Average Increase***
Domestic	6.8%
General Service 0-10kW	4.1%
General Service 10-100 kW (110 kVA)	4.1%
General Service 110-1000 kVA	5.1%
General Service 1000 kVA and Over	6.1%
Street and Area Lighting	6.1%

as set out in Schedule A to the Application.

C. Order Requested:

15. Newfoundland Power requests that the Board make an Order approving:

(a) pursuant to Section 80 of the Act, the discontinuation of use of the Formula as set out in paragraph 7 of the Application;

(b) pursuant to Section 58 of the Act, the adoption of the accrual method of accounting for other post employment benefits and for income tax related to other post employment benefits as set out in paragraph 8 of the Application;

(c) pursuant to Sections 58 and 80 of the Act, the Pension Expense Variance Deferral Account as set out in paragraph 9 of the Application;

(d) pursuant to Sections 58 and 80 of the Act, the amortizations set out in paragraph 10 of the Application;

(e) pursuant to Section 68 of the Act, that the next depreciation study relate to plant in service as of December 31, 2009 as set out in paragraph 11 of the Application;

(f) pursuant to Sections 58 and 80 of the Act, continued use of the Energy Supply Cost Variance clause and the Demand Management Incentive Account until further Order of the Board as set out in paragraph 12 of the Application;

(g) pursuant to Sections 70 and 80 of the Act, rates, tolls and charges as set out in paragraphs 13 and 14 of the Application subject to modification for any intervening Order of the Board affecting rates, tolls and charges; and

(h) such other or alternate matters which may, upon hearing of the Application, appear just and reasonable in the circumstances.

D. Communications:

16. Communication with respect to this Application should be forwarded to the attention of Ian F. Kelly, Q.C. and Gerard M. Hayes, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland, this 28th day of May, 2009.

NEWFOUNDLAND POWER INC.

Ian F. Kelly, Q.C. and Gerard M. Hayes
Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5609
Telecopier: (709) 737-2974
Internet: ghayes@newfoundlandpower.com

IN THE MATTER OF the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47, as amended, (the "Act"); and

IN THE MATTER OF a general rate application (the "Application") by Newfoundland Power Inc. ("Newfoundland Power") to establish customer electricity rates for 2010.

AFFIDAVIT

I, Peter Alteen, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Vice-President, Regulatory Affairs, of Newfoundland Power.

2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN at St. John's
in the Province of Newfoundland and Labrador
this 28th day of May, 2009,
before me:

Barrister

Peter Alteen

NEWFOUNDLAND POWER INC.
RATE #1.1
DOMESTIC SERVICE

Availability:

For Service to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect May 28, 2009)

Basic Customer Charge: .... $15.56 per month

Energy Charge:
All kilowatt-hours .... @ 10.370¢ per kWh

Minimum Monthly Charge .... $15.56 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.1
GENERAL SERVICE 0-10 kW

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect May 28, 2009)

Basic Customer Charge: .... $17.85 per month

Energy Charge:
All kilowatt-hours .... @ 12.243 ¢ per kWh

Minimum Monthly Charge, Single Phase .... $17.85 per month
Three Phase .... $35.70 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.2
GENERAL SERVICE 10-100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect May 28, 2009)

Basic Customer Charge: .... $20.55 per month

Demand Charge:
$8.62 per kW of billing demand in the months of December, January, February and March and $7.12 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kW of billing demand .... @ 9.696 ¢ per kWh
All excess kilowatt-hours .... @ 7.251 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 17.3 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

Single Phase .... $20.55 per month
Three Phase .... $35.70 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.2
GENERAL SERVICE 10-100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect May 28, 2009)

Basic Customer Charge: .... $20.55 per month

Demand Charge:
$8.62 per kW of billing demand in the months of December, January, February and March and $7.12 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kW of billing demand .... @ 9.696 ¢ per kWh
All excess kilowatt-hours .... @ 7.251 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 17.3 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

Single Phase .... $20.55 per month
Three Phase .... $38.70 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.3
GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect May 28, 2009)

Basic Customer Charge: .... $92.53 per month

Demand Charge:
$7.45 per kVA of billing demand in the months of December, January, February and March and $5.95 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 30,000 kilowatt-hours .... @ 9.634 ¢ per kWh
All excess kilowatt-hours .... @ 7.147 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 17.3 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.4
GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect May 28, 2009)

Basic Customer Charge: .... $185.08 per month

Demand Charge:
$7.04 per kVA of billing demand in the months of December, January, February and March and $5.54 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 100,000 kilowatt-hours .... @ 8.209 ¢ per kWh
All excess kilowatt-hours .... @ 7.063 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 17.3 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular, Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #4.1
STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service where the electricity is supplied by the Company and all fixtures, wiring and controls are provided, owned and maintained by the Company.

Monthly Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect May 28, 2009)

	Sentinel/Standard	Post Top
High Pressure Sodium*		
100W (8,600 lumens)	$16.35	$17.52
150W (14,400 lumens)	21.00	-
250W (23,200 lumens)	28.46	-
400W (45,000 lumens)	39.55	-

* For all new installations and replacements.

Mercury Vapour		
175W (7,000 lumens)	$16.35	$17.52
250W (9,400 lumens)	21.00	-
400W (17,200 lumens)	28.46	-

Special poles used exclusively for lighting service**

Wood	$ 6.96
30' Concrete or Metal, direct buried	10.10
45' Concrete or Metal, direct buried	15.39
25' Concrete or Metal, Post Top, direct buried	7.79

Underground Wiring (per run)**

All sizes and types of fixtures	$12.31

** Where a pole or underground wiring run serves two fixtures paid for by different parties, the above rates for such poles and underground wiring may be shared equally between the two parties.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{\text{(Maximum Demand during Peak Period x 1573 hours)}}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:

1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced by 50% as a result of the first failure to Curtail during a Winter. For each additional failure to Curtail, the Curtailment Credit will be reduced by a further 25% of the Curtailment Credit. If the Customer fails to Curtail three times during a Winter, the Customer forfeits 100% of the Curtailment Credit and the Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

SECTION 1: INTRODUCTION

1.1 APPLICATION BACKGROUND

The business of Newfoundland Power (the "Company") is principally electricity delivery and customer service. Both the Company's electricity system and the market it serves are relatively mature.

Table 1-1 shows the number of customers served by Newfoundland Power and the annual weather adjusted sales of the Company for the period 2007 through 2009F.

Table 1-1
Customers and Sales: 2007 to 2009F

	2007	2008	2009F
Number of Customers	232,262	235,778	238,901
Annual Sales (GWh)	5,093	5,208	5,303

From 2007 through 2009F, the number of customers served by Newfoundland Power is increasing by an average of 1.4% per year and annual weather adjusted sales are increasing by an average of 2% per year. Currently, the price of the electricity Newfoundland Power delivers to its customers is approximately 5.9% higher than it was at the end of 2006.[1]

Newfoundland Power's primary source of electricity supply is Newfoundland and Labrador Hydro ("Hydro") which generates approximately 93% of the electricity Newfoundland Power delivers to its customers.

[1] For 2007, a 2.8% decrease in Newfoundland Power's customer rates was the combined result of a reduction due to operation of the automatic adjustment formula and an increase as a result of a Hydro General Rate Application. For 2008, an 8.9% increase in Newfoundland Power's customer rates was the combined result of increases resulting from a Newfoundland Power General Rate Application and the operation of rate stabilization mechanisms. Current customer rates do not reflect an expected 6.6% decrease in customer rates on July 1st 2009 as a result of rate stabilization mechanisms.

Electrical service delivery for Newfoundland Power is evolving. There are a number of influences contributing to this. One is the changing expectations of Newfoundland Power's customers. Another is the mix of costs required to maintain least cost reliable service. A third influence is Newfoundland Power's workforce demographics. These influences are reflected in an increased focus on customer energy conservation programs and services; reduced levels of capital expenditure targeted at plant replacement and increased levels of capital expenditure to serve increased customer energy requirements; and a larger forecast workforce in the short term to ensure the continuity of the necessary skills required to serve customers over the long term. These influences affect the cost of the service Newfoundland Power provides to its customers.

Market conditions also influence the cost of the service Newfoundland Power provides to its customers. Financial market conditions affect the cost of the capital required by Newfoundland Power to fund the investment necessary for least cost reliable customer service. Financial market conditions also affect Newfoundland Power's costs directly, as in the case of the Company's pension costs. Commodity and foreign exchange market conditions determine the cost of No. 6 fuel used at Hydro's Holyrood thermal generating station ("Holyrood") which is the primary source of variability in Newfoundland Power's electricity supply costs.

Developments in accounting standards have the potential to materially impact Newfoundland Power's financial reporting. Important aspects of the proposed adoption of International Financial Reporting Standards ("IFRS") in 2011 by rate-regulated enterprises such as Newfoundland Power are unlikely to be settled prior to June 2010. Changes in accounting standards may not affect Newfoundland Power's cost of providing service to customers in a direct way. However, the uncertainty surrounding the future treatment of regulatory assets and liabilities under IFRS has regulatory implications.

Since 2007, Newfoundland Power has experienced material changes in its costs. Aggregate capital expenditure at year end 2010 is now forecast to be approximately $35 million higher than was expected in 2007. For 2010, both conservation and pension costs are expected to materially increase. While current short-term debt costs are at historic lows, the cost of long-term debt has increased. These specific cost changes are integral to this Application.

1.2 THE APPLICATION

1.2.1 2010 Revenue Requirements

In this Application, Newfoundland Power is requesting an average increase in current customer rates of approximately 6.1% in 2010. This increase results from four primary changes in Newfoundland Power's 2010 cost of service.

In order to sustain Newfoundland Power's financial integrity in current market conditions, the Company is targeting a 2010 return on equity of 11%. The return on equity currently reflected in customer rates is 8.95%. An approximate 2% increase in current customer rates is required to change the Company's 2010 return on rate base to reflect a return on common equity of 11% as opposed to 8.95%.

Increases in 2010 operating costs account for an approximate 1.3% increase in current customer rates for 2010. The majority of the forecast 2010 operating cost increase relates to two specific items. One is increased pension expense. In 2010, Newfoundland Power's pension expense is forecast to increase to a level comparable to 2007. The second is increased costs associated with higher levels of customer energy conservation programming. In 2010, Newfoundland Power's conservation costs are forecast to increase by over $2 million compared to 2007.

Newfoundland Power is filing a 2010 test year in this Application. This requires forecast electricity supply costs to be balanced with forecast revenue from rates for 2010. Absent the filing of this Application, electricity supply cost increases in 2010 would have been recovered through the existing energy supply cost variance mechanism in 2011. The effect of balancing 2010 test year supply costs with revenue from rates accounts for an approximate 1.1% increase in current customer rates for 2010.

In this Application, Newfoundland Power proposes to commence recognizing other post employment benefits on an accrual basis in 2010. This will result in Newfoundland Power's accounting practice being consistent with current Canadian public utility practice. Implementing this accounting change in 2010 accounts for an approximate 1% increase in current customer rates for 2010.

In addition to these four primary changes, other factors affect the proposed 2010 revenue requirements contained in this Application. These include proposed amortizations of application process costs and 2009 conservation costs. They also include increased finance and depreciation costs associated with rate base growth.

1.2.2 Other Proposals

The Company is proposing that Domestic customers receive an increase approximately 0.7% higher than the average increase in rates of 6.1%. Most General Service customers are proposed to receive an increase 1% to 2% below the average increase in rates of 6.1%. These proposals will ensure greater fairness in recovery of Newfoundland Power's cost of service by customer class.

In response to the current volatility in financial markets, this Application also proposes discontinuing use of the automatic adjustment formula, and changes in annual pension expense recovery.

Finally, Newfoundland Power proposes to complete its next depreciation study one year earlier than required by Order No. P.U. 32 (2007). This is to facilitate the Company's adoption of IFRS in 2011. It is proposed that the next depreciation study relate to plant in service as at December 31, 2009.

SECTION 2: CUSTOMER OPERATIONS

2.1 OVERVIEW

Current least cost customer service delivery for Newfoundland Power reflects the expectations of customers, the condition of the electrical system and workforce requirements.

Customer energy conservation programming is becoming a more prominent component of Newfoundland Power's service. This is responsive to current customer expectations and electrical system economics.

Reduced levels of capital expenditure to replace electrical system assets are expected. This reflects the current condition of the electrical system. However, increased capital expenditure to serve customers' increasing electricity requirements is expected.

Recruitment and training of the workforce necessary to ensure long term fulfilment of Newfoundland Power's customer service obligations is increasing the cost of service delivery to customers. This is necessary to address current workforce demographics.

2.2 SERVING CUSTOMERS

Customers' satisfaction with Newfoundland Power's service is consistent with recent experience.

This section of evidence outlines how Newfoundland Power responds to evolving customer expectations.

The number of customer initiated contacts with Newfoundland Power is growing, with customers increasingly choosing to interact with Newfoundland Power via electronic means.

Customer energy conservation is becoming an increasingly prominent component of Newfoundland Power's overall customer service mix.

2.2.1 Responding to Customer Expectations

Newfoundland Power's customer satisfaction index was 88% in 2007 and 89% in 2008.[1] This is consistent with customer satisfaction over the past decade.[2]

As customers' expectations evolve, Newfoundland Power's response to those expectations also evolves. A principal aspect of the evolution of customer expectations in recent years relates to how customers choose to interact with Newfoundland Power.

[1] Customer satisfaction surveys have been conducted by the Company on a quarterly basis since 1997. The survey asks customers to rate their overall satisfaction level with the Company and its Customer Contact Centre and field service on a scale of 1 to 10 with 1 being "not at all satisfied" and 10 being "fully satisfied". A 90% customer satisfaction rating would reflect an overall weighted average satisfaction of 9 from survey respondents. Responses are averaged and weighted for Domestic and General Service customer classes. Annual customer satisfaction statistics average the results of these quarterly surveys.

[2] Customer satisfaction has ranged from 84% in 1998 to 91% in 2002. In the 5 years ending 2008, annual customer satisfaction has been consistent at 88% to 89%.

Table 2-1 shows the number of customer initiated contacts received by Newfoundland Power at the Customer Contact Centre, the website and the outage notification system ("ONS") from 2006 through the 1st quarter of 2009.

Table 2-1
Customer Initiated Contacts
2006 to 2009
(000s)

	2006	**2007**	**2008**	**2009**[3]
Contact Centre Calls	520	541	495	126
Website	355	393	470	171
Email[4]	17	24	33	12
ONS[5]	73	102	75	29
Total	**965**	**1,060**	**1,073**	**338**

The number of customer calls to the Customer Contact Centre decreased by 5% during this period. However, customers' website contact with Newfoundland Power has increased by 32% and email communication has increased by 94%.[6]

Average call duration is increasing due to the changing nature of customer inquiries. Customers are increasingly choosing to access the Company's Customer Contact Centre for technical

[3] 1st Quarter 2009.
[4] Customer emails are predominately received via the website and the Customer Contact Centre, and are predominately responded to by Contact Centre staff.
[5] The Outage Notification System provides customers with an automated message containing the reason for a system outage together with estimated service restoration time. The ONS can answer 256 simultaneous calls per minute for each of the Company's eight operating areas.
[6] Customers are also increasingly choosing electronic means for bill presentment and payment. From 2006 to 2008, the number of customers participating in the Company's *eBills* electronic bill presentment program increased from approximately 11,400 to 23,200, or 104%. In 2008, over 68% of the Company's customer bill payments were received electronically.

services and energy conservation information and initiatives.[7] Customers are increasingly using electronic means for simpler inquiries such as account balances.[8]

Newfoundland Power's customers' interest in energy conservation is increasing.[9] In June 2008, Hydro and Newfoundland Power created a 5-year energy conservation plan (the "Conservation Plan").[10] The Conservation Plan responds to customer expectations regarding energy conservation information.[11] The Conservation Plan also provides for specific customer energy conservation programming.

In 2009, Hydro and Newfoundland Power will commence delivery of an expanded portfolio of customer energy conservation programs. The conservation program portfolio will include rebate and incentive programs to promote high efficiency windows, thermostats and insulation for Domestic customers, as well as high efficiency lighting for General Service customers.[12]

Newfoundland Power's primary responsibility under the Conservation Plan is the development and delivery of programs for the residential and commercial sectors, while Hydro is focused on

---

7 In 2006 there were approximately 14,000 technical and field calls from customers and approximately 9,200 energy conservation calls. In 2008, the approximate numbers of these types of calls were 15,500 and 14,000, respectively. Technical and energy conservation customer contacts tend to be the longest duration calls.

8 Between 2006 and 2008 approximately 90% of customers who contacted the Customer Contact Centre to ascertain their account balance chose the self-serve interactive voice response option to access this information rather than speak to a call centre agent. In addition, approximately 182,000 visits per year to Newfoundland Power's website accessed customer account information.

9 Total energy conservation calls to the Customer Contact Centre increased by over 50% between 2006 and 2008.

10 This plan was filed with the Board in June, 2008. In Order No. P.U. 13 (2009), the Board approved the creation of an account to permit deferred recovery of Newfoundland Power's costs associated with 2009 implementation of customer energy conservation programming outlined in the plan.

11 Approximately 64% of Newfoundland Power's customers indicate their preferred source of information on energy efficiency is their electric utility. *Customer Energy Efficiency Attitude Survey*, May 2008.

12 The Conservation Plan, including the specific programs, was before the Board in Newfoundland Power's *2009 Conservation Cost Deferral Application* which was filed October 29, 2008 and approved in Order No P.U. 13 (2009). Hydro filed a complementary application with the Board on November 21, 2008.

programs for the industrial sector. This division of primary responsibilities reasonably reflects utility responsibilities on the province's electrical system.[13]

The joint efforts of Hydro and Newfoundland Power in developing the Conservation Plan and providing customer energy conservation programs are consistent with least cost service delivery. They are also consistent with the coordinated approach indicated in the *Energy Plan*.[14]

The Conservation Plan is aimed at *energy* conservation and responds to the high marginal cost of energy on the electrical system.[15] Delivery of the programs under the Conservation Plan will reduce energy consumption and electricity bills for customers who choose to participate in the programs. Customers who choose not to participate in the programs will also benefit in terms of reduced long-term system supply costs. Program delivery will increase Newfoundland Power's costs. The economic benefits for customers are, however, expected to be materially greater than the additional costs.[16]

Customer energy conservation will tend to yield peak demand reductions over time.[17] Newfoundland Power also takes measures to reduce peak demand on the electrical system.

---

[13] Execution of the Conservation Plan is a *joint* Hydro and Newfoundland Power initiative. Accordingly, while Newfoundland Power is *primarily* responsible for development and delivery of residential and commercial programs, Hydro actively participates in program development and is responsible for delivery of programs to its customers.

[14] See Government of Newfoundland and Labrador's *2007 Energy Plan*, p.58.

[15] In the near-term, the benefits associated with implementing these programs will be principally reflected in reduced fuel consumption at Hydro's Holyrood thermal generating station.

[16] It is expected that Newfoundland Power's implementation of customer energy conservation programs in 2009 will result in energy savings of 15 GWh per year by 2013. The portfolio Total Resource Cost test result of 2.7 for Newfoundland Power's programming indicates that implementation will yield a benefit to cost ratio for customers in the order of 2.7 to 1. The aggregate Ratepayer Impact Measure of 1.28 for the residential and commercial components of the portfolio indicates that their implementation should not result in non-participants bearing additional cost.

[17] These benefits are recognized in the results of the economic analyses referred to in footnote 16.

Newfoundland Power coordinates generation dispatch with Hydro as required to meet demand on the Island interconnected grid.[18] Newfoundland Power also has a Curtailable Service Option for its customers, which incents customers to reduce demand at the Company's request when peak demand is forecast. In addition, Newfoundland Power has approximately 2.5 MW of curtailable load from its own facilities, and has a limited ability to control system voltages to reduce peak demand.[19]

Demand management is consistent with the continued least cost reliable operation of the Island interconnected grid and provides benefits to Newfoundland Power's customers.[20]

2.2.2 The Electrical System

Newfoundland Power's service reliability performance is currently satisfactory on a system wide basis.

This section of evidence reviews Newfoundland Power's electrical system performance.

Reduced levels of capital expenditure aimed at replacement of electrical system assets are reflective of current system reliability. The costs necessary to serve growth in the number of

---

[18] Hydro requests Newfoundland Power's dispatch of its generation facilities as needed to meet the requirements of the Island interconnected grid. While these requests can occur at any time in a year, they tend to be more frequent in the winter season (i.e., between December and March) when demand on the Island interconnected grid is highest. In the December 2008 through March 2009 winter season, Hydro made 4 requests for Newfoundland Power to dispatch its generation.

[19] Newfoundland Power's use of any or all of these alternatives is typically coordinated with Hydro's overall system control of the Island interconnected grid.

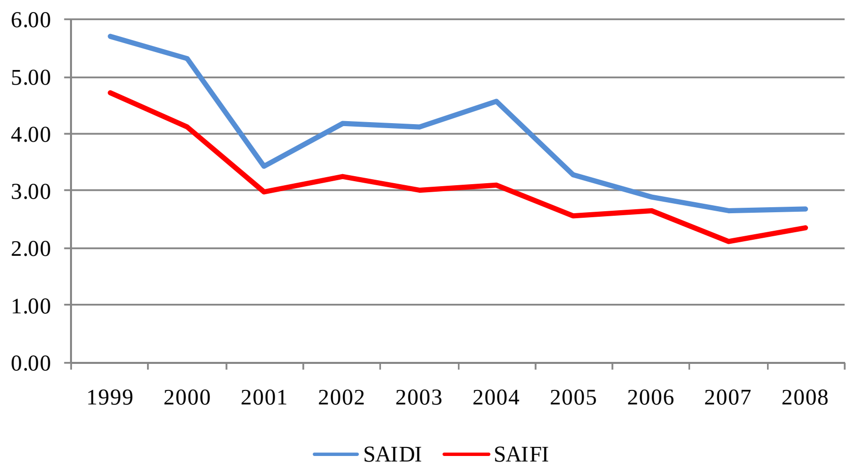
[20] There are transparent economic benefits for Newfoundland Power's customers from their reduced aggregate demand. Between 2005 and 2008, there have been approximately $3.2 million of demand related wholesale supply cost reductions credited to customers' benefit as a result of supply cost recovery mechanisms approved by the Board. See Section 5: Customer Rates, *5.4.1 Demand Management Incentive Account* at p.5-12. For customers who elect to be served under the Curtailable Service Option, the benefits also include reduced electricity rates.

customers have been increasing in recent years. This has been primarily reflected in increased capital expenditure to connect additional customers. In the future, increased costs associated with additional capacity to meet growing customer electricity requirements are expected.

Electrical System Reliability

Graph 2-1 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 1999 through 2008. Graph 2-1 has been adjusted to remove the effects of severe weather events.[21]

Graph 2-1
SAIDI and SAIFI
1999 to 2008



The overall trend in SAIDI and SAIFI indicates improved electrical system reliability. In 2008, the average number of customer *hours* of outage was approximately one half of that in 1999.[22] Similarly, in 2008 the average *number* of customer outages was approximately one half of that in 1999.[23]

[21] Adjustments exclude 1999 Burin and 2007 Bonavista severe weather events. If these were included, 1999 SAIDI and SAIFI would be 9.37 and 5.28, respectively; and 2007 SAIDI and SAIFI would be 5.94 and 2.46, respectively.

[22] In 1999, SAIDI was 5.7 hours. In 2008, SAIDI was 2.7 hours (2.7 / 5.7 = 0.47).

[23] In 1999, SAIFI was 4.7 outages. In 2008, SAIFI was 2.4 outages (2.4 / 4.7 = 0.51).

Newfoundland Power considers current levels of service reliability to be satisfactory. This reflects the current condition of Newfoundland Power's electrical system assets.[24]

The majority of Newfoundland Power's annual capital expenditure is focused on the replacement and refurbishment of deteriorated assets.[25] This improves the condition of the electrical system. The improved condition of the electrical system has resulted in lower levels of operating cost.[26] Plant replacement is expected to continue to be the primary focus of Newfoundland Power's capital expenditures although at slightly reduced levels.[27]

Newfoundland Power specifically targeted improvement in radial distribution system performance over the past decade.[28] In the ten years ending in 2008, Newfoundland Power invested a total of $14 million in the Distribution Reliability Initiative ("DRI"), which focused on rebuilding the worst performing feeders in the system.[29] Reduced DRI expenditure is expected in the future.

---

[24] It is a generally accepted engineering observation that electrical system reliability is primarily influenced by the condition of the electrical system assets.

[25] In the five years ending 2009, asset replacement accounted for approximately 57% of Newfoundland Power's capital expenditure.

[26] The strengthening of the electrical system has been key to Newfoundland Power's ability to reduce the size of its workforce through a series of early retirement programs over the past decade or so. This workforce reduction resulted in a sustained period of flat operating costs during which service to customers improved. It was improved reliability associated with better plant condition that largely enabled the reduction in workforce without compromising service to customers.

[27] In the five years to 2014, asset replacement is forecast to account for approximately 51% of Newfoundland Power's capital expenditure.

[28] Rural areas are typically served by radial distribution systems, while urban areas are typically served by looped systems. Looped distribution systems are not feasible in rural areas principally for geographic and economic reasons.

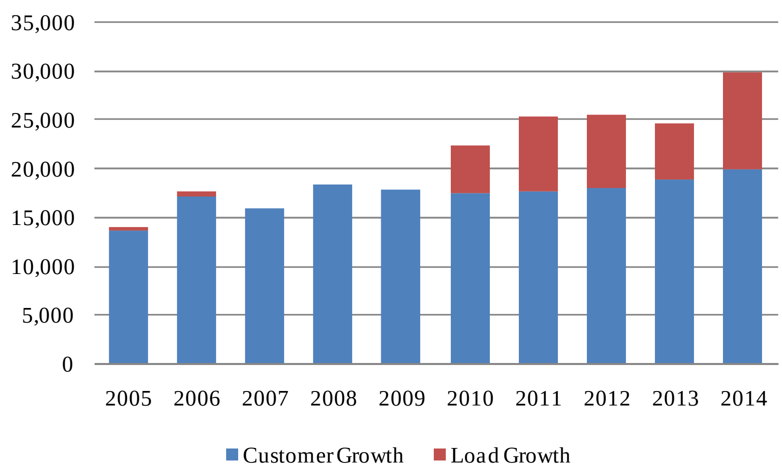
[29] D. G. Brown, P.Eng in his 1998 report *Newfoundland Light & Power Co. Limited Quality of Service and Reliability of Supply*, prepared for the Board of Commissioners of Public Utilities, identified the need for Newfoundland Power to improve reliability.

Serving Customer Growth

The portion of Newfoundland Power's annual capital investment related to customer growth ("Customer Growth Capital") is increasing.[30] The level of Customer Growth Capital reflects a number of factors. One is an increase in the number of customers that Newfoundland Power serves. Another is an increase in the amount of electricity delivered by Newfoundland Power to its customers.

Graph 2-2 shows Newfoundland Power's Customer Growth Capital for the years 2005 through 2014F.

Graph 2-2
Customer Growth Capital
2005 to 2014F
($000s)



Customer Growth Capital in the five years ending in 2009F consists largely of the cost of connecting additional customers.[31]

---

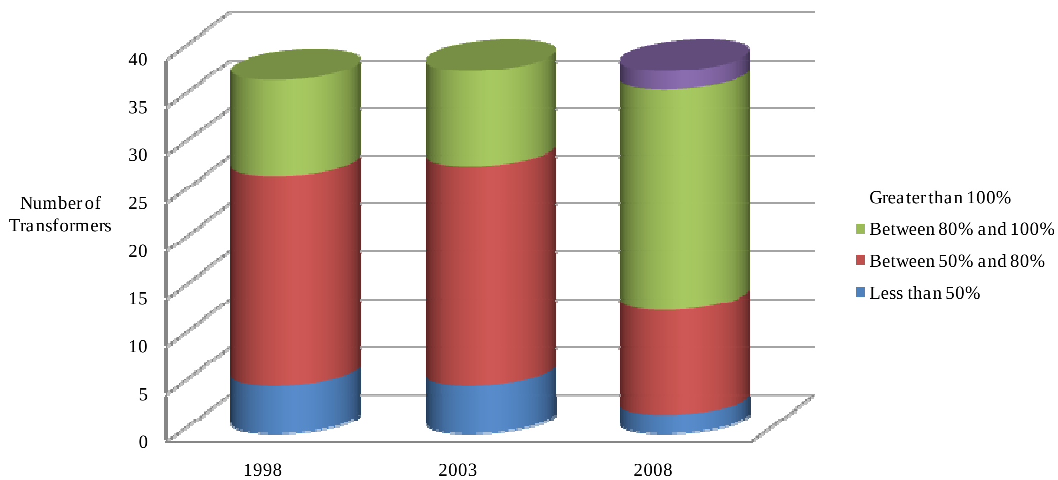
[30] In the five years ending 2009, approximately 28% of Newfoundland Power's capital investment was Customer Growth Capital. In the five years ending 2014, approximately 36% of Newfoundland Power's annual capital investment is forecast to be Customer Growth Capital.

[31] Over the five years ending in 2008, growth in the number of Newfoundland Power customers was approximately 41% higher than that in the five years ending in 2003.

In the five years ending 2014, the cost of connecting customers will continue to be a significant component of Customer Growth Capital. However, during the period, Customer Growth Capital is forecast to include significant investment to serve increasing customer electricity requirements. This investment will be required to increase system capacity, particularly power transformation capacity.[32]

Graph 2-3 shows power transformer capacity utilization on peak for power transformers located in the St. John's CMA[33] for each of 1998, 2003, and 2008.

Graph 2-3
St. John's Metropolitan Area
Power Transformer Capacity Utilization
1998, 2003 and 2008



In 1998, approximately 27% of distribution power transformers in the St. John's CMA had capacity utilization on peak of 80% or greater.[34] By 2008, the proportion of distribution power

[32] Transformation of voltage is an essential aspect of electrical system operations. Each distribution power transformer has a specified capacity to transform voltage. Capacity is measured in megawatts ("MW") and is the maximum *sustained* power output of the electrical device. As customer load on a circuit connected to a transformer increases, the capacity of the transformer is utilized. A key component of electrical power system planning relates to ensuring future transformer capacity is sufficient to meet future customer load requirements.

[33] The St. John's Census Metropolitan Area (CMA) as defined by Statistics Canada.

[34] In 1998, 10 of a total of 37 distribution power transformers in the St. John's CMA had capacity utilization on peak of 80% or greater. (10 / 37 = 0.27).

transformers in the St. John's CMA with capacity utilization on peak of 80% or greater had grown to approximately 66%.[35]

The increase in capacity utilization of distribution power transformers in the St. John's CMA reflects growth trends over the decade ended in 2008.[36] Growth in capacity utilization of distribution power transformers in the remainder of the Company's service territory has been less dramatic.[37]

Forecast increases in customers' electricity requirements are expected to increase Customer Growth Capital in the future.[38]

2.2.3 Workforce Management

Workforce management for Newfoundland Power has both a short term and a long term perspective. In the short term, the Company matches its workforce with year to year requirements. To be prepared for the long term, the Company seeks to ensure sufficient workforce development to maintain least cost reliable service for its customers.

This section of evidence reviews Newfoundland Power's workforce management.

---

[35] In 2008, 25 of a total of 38 distribution power transformers in the St. John's CMA had capacity utilization on peak of 80% or greater. (25 / 38 = 0.66).

[36] Over the 5 years ended 2008, the amount of energy consumed by Newfoundland Power customers increased by 306 GWh. Approximately 76% of this increase, or 234 GWh, occurred in the St. John's CMA. Customers in the St. John's CMA also accounted for the majority of energy growth in the previous 5 years.

[37] In 1998, 14 of a total of 93, or 15%, of distribution power transformers outside of the St. John's CMA had capacity utilization on peak of 80% or greater. In 2008, 24 of a total of 96, or 25%, of distribution power transformers outside of the St. John's CMA had capacity utilization on peak of 80% or greater.

[38] In the 15 years ending 2008, Newfoundland Power installed 5 distribution power transformers to serve increasing customer demand and energy requirements. Of these, 2 serve the St. John's CMA. In the 5 years ending 2013, Newfoundland Power forecasts a requirement for 7 additional distribution power transformers. Of these, 4 are forecast to be required to serve the St. John's CMA.

Demographics are a prominent feature of workforce management at Newfoundland Power. Management of workforce demographics is increasing the cost of service delivery to customers.

Table 2-2 shows Newfoundland Power's workforce as expressed in full-time equivalents ("FTEs") for the period 2007 through 2010F.

Table 2-2
Newfoundland Power Workforce
FTEs

	2007	**2008**	**2009F**	**2010F**[39]
Regular	555	551	574	579
Temporary	72	77	67	72
Total	**627**	**628**	**641**	**651**

Part of the forecast increase in Newfoundland Power's workforce through 2010 reflects changes in the work requirements of the Company. For example, 6 additional hires are necessary in 2009 to implement the Conservation Plan. It also reflects adjustments required to address the specific composition of forecast 2010 work requirements.[40] For example, in 2008 the Company hired 4 Technologists on a temporary basis to accommodate an increase in engineering design work related to the Company's capital program.[41]

[39] An explanation of the method used to forecast 2010 FTEs and labour expense together with an explanation of assumptions concerning forecast vacancies is found in Labour Forecast 2009-2010, *Volume 2: Supporting Materials, Tab 1.*

[40] This includes both capital and operating work requirements. In fulfilling these requirements, the Company's choices include its regular workforce, its temporary workforce, and contractors. At any point in time, these choices will be influenced by the specific work requirements.

[41] The alternative to retaining temporary technical staff for capital work is to contract this work to a consulting engineering firm. If the work was performed by a consulting engineering firm, there would be no impact on the Company's workforce (FTEs). Retaining technologists is lower cost in circumstances where the volume of work is relatively high. Retaining staff on a temporary basis also permits the Company a better opportunity to meaningfully assess longer-term employment potential within the context of broader workforce demographics.

Part of the forecast increase in Newfoundland Power's workforce through 2010 is attributable to the need to address workforce demographics, primarily the aging workforce.[42]

Skilled and technical labour is at the core of Newfoundland Power's capability to provide service to its customers. Skilled tradespersons account for approximately 33% of Newfoundland Power's current workforce.[43] Technologists and Engineers account for a further 19%.[44] Newfoundland Power's management of workforce demographics is focused on ensuring continuity in its skilled and technical workforce.

Table 2-3 shows the number of Powerline Technicians employed by the Company at year end 2007 through 2010F.

Table 2-3
Powerline Technicians

	2007	**2008**	**2009F**	**2010F**
Journeypersons	128	124	123	123
Apprentices	11	19	24	26
Total	**139**	**143**	**147**	**149**

Between 2007 and 2010, the number of Apprentice Powerline Technicians is forecast to increase from 11 to 26. Apprentice Powerline Technicians are expected to account for approximately

[42] The average age of Newfoundland Power's current workforce is 47.6 years of age. Approximately 46% of the workforce is 50 years of age or older.

[43] At the time of writing, of the 660 persons (as opposed to FTEs) employed by Newfoundland Power, 219 held the qualifications of Powerline Technicians, Apprentice Powerline Technicians or other skilled trades. (219 / 660 = 0.33)

[44] At the time of writing, of the 660 persons (as opposed to FTEs) employed by Newfoundland Power, 124 held the qualifications of Technologists or Engineers. (124 / 660 = 0.19)

17% of the total number of Powerline Technicians by year end 2010. Apprentice employment at this level will be necessary for the foreseeable future to ensure continuity in this skilled trade.[45]

The employment and development of these additional Apprentice Powerline Technicians will tend to add cost.[46] This dynamic will apply in varying degrees to Newfoundland Power's overall management of workforce demographics.[47]

2.3 2010 OPERATING AND CAPITAL COSTS

To establish 2010 customer rates, the Board must consider Newfoundland Power's 2010 operating and capital costs.

This section of the evidence reviews the forecast 2010 operating and capital costs for Newfoundland Power and provides analysis of material cost changes for the period 2007 through 2010F.

---

[45] While the Apprentice Powerline Technician program provides for 5 years' education and training to achieve Journeyperson qualification, full development of a Powerline Technician typically requires more experience. For example, the *International Brotherhood of Electrical Workers* has observed that it takes 10 years to become a well-rounded Powerline Technician.

[46] The work performed by Newfoundland Power's Powerline Technicians is predominantly distribution operations and capital work. Therefore, increased costs associated with their development will tend to be reflected in distribution operating and capital costs. Because new apprentices are principally engaged in capital work, the costs associated with an increased number of apprentices will initially tend to be reflected more in capital costs. As their training progresses, the cost of apprentices will tend to be reflected more in operating costs.

[47] This dynamic reflects implicit and explicit costs of training new employees. In some cases, these additional costs are effectively reduced by differences in compensation (i.e., a junior engineer is typically paid less than a senior engineer).

2.3.1 Operating Costs

General

Operating costs are those costs over which Newfoundland Power has the greatest degree of management control. Operating costs represent approximately 10% of the Company's forecast 2010 revenue requirement.[48]

An understanding of Newfoundland Power's operating costs can be gained by examination of the costs on both a functional and a breakdown basis.

The functional classification focuses on the underlying reason for incurring a cost. The breakdown classification focuses on the nature of the cost. For example, the Company classifies the salary of a Customer Contact Centre employee in two ways: 1) by function, as a customer service cost; and 2) by breakdown, as a labour cost.

Exhibits 1 and 2 show operating costs from 2007 to 2010F by function and by breakdown, respectively.

Table 2-4 shows operating costs from 2007 actual to 2010 forecast.

Table 2-4
Operating Costs[49]
2007 to 2010F
($000s)

	2007	**2008**	**2009F**	**2010F**
Operating Costs	48,104	47,146	50,990	52,758

Total operating costs for 2010 are forecast to increase by approximately 10% over 2007.

48 Exhibit 7 contains the proposed revenue requirements for 2010.
49 These amounts are found in Exhibit 1, line 25 and Exhibit 2, line 30. They exclude pension costs, deferred costs, and General Expenses Capitalized.

By Function

Table 2-5 summarizes operating costs by 3 functional categories: electricity supply, customer service and general for 2007 to 2010F.[50]

Table 2-5
Operating Costs by Function
2007 to 2010F
($000s)

Function	**2007**	**2008**	**2009F**	**2010F**
Electricity Supply	21,015	20,945	21,519	22,265
Customer Service	10,273	10,405	12,335	13,017
General	16,816	15,796	17,136	17,476
Total	**48,104**	**47,146**	**50,990**	**52,758**

Table 2-6 shows the operating costs associated with the electricity supply category broken out by function for 2007 to 2010F.

Table 2-6
Operating Costs – Electricity Supply
2007 to 2010F
($000s)

Function	**2007**	**2008**	**2009F**	**2010F**
Distribution	6,575	6,683	7,068	7,365
Transmission	587	585	569	585
Substations	2,311	2,123	2,319	2,432
Power Produced	2,480	2,586	2,652	2,723
Administration & Engineering	5,585	5,604	5,734	5,879
Telecommunications	1,399	1,394	1,387	1,380
Environment	581	398	398	409
Fleet Operations & Maintenance	1,497	1,572	1,392	1,492
Electricity Supply	**21,015**	**20,945**	**21,519**	**22,265**

Electricity supply costs for 2010 are forecast to increase 6%, or approximately $1.3 million, compared to 2007.

[50] Newfoundland Power has historically categorized its functional operating costs in this way to permit ease of explanation.

Electricity supply costs include electrical system operations and maintenance activity and reflect increases in costs for labour and materials. Distribution operating costs reflect system maintenance, including increased trouble response, to address equipment failure.[51] They also include increased labour costs associated with skilled trades and apprenticeship development. Substations operating costs reflect ongoing system maintenance costs.[52] Power produced operating costs reflect increased fees related to water use licence renewals associated with the Company's hydroelectric plants. Fleet operations and maintenance costs reflect year over year variations in fuel prices.

Table 2-7 shows costs associated with the customer service category broken out by function for 2007 to 2010F.

Table 2-7
Operating Costs – Customer Services
2007 to 2010F
($000s)

Function	**2007**	**2008**	**2009F**	**2010F**
Customer Services	9,180	9,571	8,921	9,077
Conservation[53]	-	-	2,451	2,977
Uncollectible Bills	1,093	834	963	963
Customer Services	**10,273**	**10,405**	**12,335**	**13,017**

[51] In the two year period ending in 2008, trouble calls responded to by the Company increased 3.4%.

[52] 2008 substation costs were lower due to unanticipated 2008 capital requirements associated principally with the connection of two wind generating facilitates to the Island interconnected grid. To accommodate connection of the wind generation facilities in a timely way, the Company was required to redirect labour forces originally scheduled for maintenance activities to the connection work. 2009 and 2010 forecast substation costs are reflective of long term maintenance needs of the Company.

[53] Prior to 2009, conservation costs were not classified separately by function and were principally reflected in the customer services functional class. For comparative purposes Table 2-8 below shows estimated conservation costs from 2007 through 2008 together with forecast 2009 and 2010 costs.

Table 2-8
Conservation Costs
2007 to 2010F

	2007	**2008**	**2009F**	**2010F**
General	469	581	915	1,108
Customer Programs	175	170	1,536	1,869
Total	**644**	**751**	**2,451**	**2,977**

Customer service operating costs for 2010 are forecast to increase 27%, or approximately $2.7 million, compared to 2007.

Customer service operating costs are increasing principally due to conservation initiatives, including increased customer energy conservation programming undertaken by Newfoundland Power.[54]

Table 2-9 shows the costs associated with the general category broken out by function for 2007 to 2010F.

Table 2-9
Operating Cost – General
2007 to 2010F
($000s)

Function	**2007**	**2008**	**2009F**	**2010F**
Information Systems	2,752	2,487	2,736	2,817
Financial Services	1,646	1,502	1,571	1,658
Corporate & Employee Services	10,777	10,463	11,729	11,901
Insurances	1,641	1,344	1,100	1,100
General	**16,816**	**15,796**	**17,136**	**17,476**

General costs for 2010 are forecast to increase 4%, or approximately $0.7 million, compared to 2007.

Information systems and corporate & employee services costs were lower in 2008 as a result of one-time changes in accounting treatment for software fees and Public Utilities Board assessment, respectively. Accordingly, 2009F information systems and corporate & employee

[54] Deferred recovery of Newfoundland Power's 2009 customer conservation programming costs was approved by the Board in Order No. P.U. 13 (2009).

services costs are approximately $300,000 and $600,000 higher, respectively, as a result of the one-time nature of the 2008 accounting treatment changes. 2009F and 2010F corporate & employee services costs reflect increased other company fees.[55] Insurance costs reflect a combination of insurance market conditions and the benefits of the Company's participation in the Fortis group insurance program.

By Breakdown

The primary breakdowns of Newfoundland Power's operating costs are labour costs and other costs.

Table 2-10 provides the breakdown of operating costs for 2007 to 2010F.

Table 2-10
Operating Cost by Breakdown
2007 to 2010F
($000s)

Breakdown	**2007**	**2008**	**2009F**	**2010F**
Labour	28,262	28,454	29,601	30,749
Other	19,842	18,692	21,389	22,009
Total	**48,104**	**47,146**	**50,990**	**52,758**

[55] Other company fees are further described at p.2-21, lines 8 to 9 and footnote 61.

Table 2-11 provides the breakdown of labour costs for 2007 to 2010F.

Table 2-11
Labour Cost by Breakdown
2007 to 2010F
($000s)

Breakdown	**2007**	**2008**	**2009F**	**2010F**
Regular and Standby	24,371	24,485	26,105	27,486
Temporary	2,303	2,335	1,860	1,623
Overtime	1,588	1,634	1,636	1,640
Total Labour	**28,262**	**28,454**	**29,601**	**30,749**

Labour costs for 2010 are forecast to increase 9%, or approximately $2.5 million, compared to 2007. This primarily reflects conservation related costs, costs associated with management of workforce demographics, and labour rate increases.[56]

Regular and standby labour costs for 2010 are forecast to increase by approximately 13%, or $3.1 million, over 2007. This increase includes $806,000 related to the change in status of employees from temporary to regular in 2009.[57]

Temporary labour costs for 2010 are forecast to decrease by approximately 30%, or $680,000, compared to 2007. This also reflects the change in status referred to above. In addition, temporary labour costs include the operating costs associated with Apprentices.

[56] Negotiated wage rate increases for skilled trades total 6.3% in 2009, 5% in 2010, and 5% in 2011. Negotiated wage rate increases for the remainder of the unionized workforce were 3% in 2009, 3% in 2010 and 3.5% in 2011. For 2010, a salary increase of 4% is forecast for management employees.

[57] As a result of collective agreements signed early in 2009, 17 employees were transferred from temporary to regular employment status. All transferred employees had in excess of 10 years employment with the Company. If this change is excluded, the change in regular and standby labour is approximately 10% or $2.3 million over the period.

Overtime labour costs for 2010 are forecast to be consistent with previous years on an overall basis. Overtime labour costs are mostly influenced by unplanned outage response.

Other costs for 2010 are forecast to increase 11%, or approximately $2.2 million, compared to 2007.[58]

The increase in other costs for 2010 compared to 2007 principally reflects forecast cost increases related to advertising ($1,040,000),[59] conservation rebates ($452,000)[60], other company fees ($360,000),[61] vegetation management ($210,000),[62] and tools and clothing ($232,000),[63] offset by a forecast decrease in the cost of insurance ($541,000).

2.3.2 Capital Costs

Newfoundland Power's annual capital budget reflects a large number of assets spread over a broad geographic area that make up the electrical system. For ratemaking purposes, a capital forecast for the 2010 test year must be considered and approved by the Board.[64]

58 Excluding additional conservation costs totalling approximately $1.6 million, Other costs are forecast to increase by approximately $0.6 million, or 3%, in 2010F compared to 2007.
59 Of the $1.040 million forecast increase in Advertising costs in 2010F compared to 2007, $900,000 is attributable to customer conservation programming.
60 Conservation rebates are forecast to be $581,000 in 2010 compared to $129,000 in 2007.
61 The $360,000 forecast increase in other company fees in 2010F compared to 2007 is principally attributable to increased fees associated with IFRS ($135,000), litigation ($100,000), and dam and surge tank safety inspections ($100,000).
62 Increased vegetation management costs principally reflect increased contractor costs in the period 2007 through forecast 2010.
63 The $232,000 forecast increase in tools and clothing costs in 2010 over 2007 is principally attributable to the Company's 2008 adoption of a fire retardant clothing standard for an expanded group of field employees.
64 Newfoundland Power's 2010 Capital Budget is expected to be the subject of a separate Application to the Board, but is not expected to be materially different from the forecast contained in this evidence.

Table 2-12 shows capital expenditures for 2007 to 2010F.

Table 2-12
Capital Expenditures
2007 to 2010F
($000s)

Function	**2007**	**2008**	**2009F[65]**	**2010F**
Generation	18,150[66]	3,920	8,999	5,429
Substations	5,077	7,063	7,204	10,218
Transmission	4,440	5,316	6,075	5,915
Distribution	30,429	35,485	30,178	31,965
General Property	1,675	1,073	835	1,381
Transportation	2,231	2,384	2,255	2,352
Telecommunications	110	266	350	379
Information Systems	3,523	3,734	3,725	3,490
Unforeseen Allowance	0	400	750	750
GEC	2,850	2,765	2,800	2,800
Total	**68,485**	**62,406**	**63,171**	**64,679**

While the 2010 capital forecast is broadly consistent on a functional basis with expenditures since 2007, trends in certain functions reflect changes in the overall focus of the Company's capital expenditure program. Substations and distribution expenditures reflect the need to expand capacity related to aggregate increases in customer load. At the same time, distribution expenditures related to plant refurbishment are declining.

Variations in transmission and generation expenditures over the period reflect specific project related fluctuations in these functions.

[65] The Company's 2009 Capital Budget was approved in Order No. P.U. 27 (2008). Forecast 2009 expenditures also include approximately $1.6 million in supplemental capital expenditures approved in Order Nos. P.U. 18 (2008) and P.U. 19 (2008).

[66] Includes approximately $17 million associated with Rattling Brook Hydro Plant Refurbishment.

SECTION 3: FINANCE

3.1 OVERVIEW

From 2007 through 2009 forecast, Newfoundland Power's achieved rate of return on rate base will have been below the midpoint used for ratemaking purposes. Achieved rates of return on equity, however, will have been consistent with those allowed for ratemaking purposes.

For 2010, Newfoundland Power forecasts deterioration of its credit metrics as a result of a decline in its forecast return on equity to approximately 6.9%. Accordingly, additional revenue will be necessary to provide the Company with an opportunity to maintain its creditworthiness and earn a just and reasonable return in 2010.

In this Application, Newfoundland Power seeks a return on equity for ratemaking purposes of 11% for 2010. In addition, the Company proposes discontinuing use of the automatic adjustment formula due to changed financial market conditions.

The volatility of current financial market conditions has increased the unpredictability of Newfoundland Power's annual pension expense. This Application proposes a means to address this increased unpredictability. Newfoundland Power also proposes to commence accrual accounting for other post-employment benefits in 2010.

To facilitate the adoption of International Financial Reporting Standards in 2011, Newfoundland Power proposes to advance the timing of its next depreciation study.

Finally, this section of the evidence reviews proposals for recovery of deferred 2009 conservation costs and third party costs associated with this Application.

3.2 FINANCIAL PERFORMANCE: 2007 to 2010

Sound financial performance is essential to the maintenance of Newfoundland Power's financial integrity.

This section of the evidence reviews the Company's actual financial performance for 2007 and 2008, and its forecast financial performance for 2009 and 2010. Exhibit 3 shows Newfoundland Power's actual financial performance for 2007 and 2008 and forecast financial performance for 2009 and 2010, excluding the effects of proposals made in this Application.

For the period 2007 through 2009, Newfoundland Power's financial performance will have been consistent with the continued financial integrity of the Company.

For 2010, forecast financial performance is not consistent with the maintenance of Newfoundland Power's financial integrity.

3.2.1 Revenue

Table 3-1 shows electricity sales and revenue from 2007 to 2010E.[1]

Table 3-1
Electricity Sales and Revenue: 2007 to 2010E

	2007	**2008**	**2009F**	**2010E**
Electricity Sales (GWh)	5,093	5,208	5,303	5,396
Sales Growth (%)	2.0	2.3	1.8	1.7[2]
Electricity Revenue ($000s)				
Revenue from Rates	474,054	497,360	506,284	511,625
2005 Unbilled Revenue[3]	2,714	7,210	4,618	4,618
RSA Transfers[4]	3,044	(948)	3,031	6,128
Total	**479,812**	**503,622**	**513,933**	**522,371**

Newfoundland Power's electricity sales reflect economic conditions, population and demographic changes and customer usage patterns.

Electricity sales growth in 2007 and 2008 was 2.0% and 2.3%, respectively.[5] Sales growth for 2009 and 2010E is forecast to moderate somewhat to 1.8% and 1.7%, respectively.[6] Electricity sales growth from 2007 through 2010E reflects increases in the number of customers served by

[1] References to 2010 with the notation 'E' (i.e., 2010E) are intended to indicate forecast results in the absence of the proposals contained in this Application. This includes the forecast effects of operation of the Formula on January 1, 2010 at an average observed ask yield for long-term Government of Canada bonds of 3.86% and a corresponding forecast *cost of equity* of 8.36% (see footnote 35). It excludes the proposals contained in this Application.

[2] 2009 and 2010 electricity sales are forecast to be 5303.3 GWh and 5395.6 GWh, respectively.

[3] In Order Nos. P.U. 39 (2006) and P.U. 32 (2007), the Board approved amortizations of the 2005 unbilled revenue as current revenue for the years 2007 through 2010. The 2005 unbilled revenue arose as a result of the Company's adoption of the accrual method of revenue recognition as of January 1, 2006 pursuant to Order No. P.U. 40 (2005).

[4] RSA transfers reflect: a 2007 flow through related to a Hydro rate change as approved in Order No. P.U. 42 (2006); a 2008 flow through related to a 2008 income tax true up approved in Order No. P.U. 10 (2008); and flow throughs related to operation of the Energy Supply Cost Variance clause approved in Order No. P.U. 32 (2007), for 2008 and forecast for 2009 and 2010.

[5] In the Supplemental Evidence filed in Newfoundland Power's 2008 General Rate Application, electricity sales for 2007 and 2008 were forecast to be 5,112 GWh and 5,215 GWh, respectively. Actual electricity sales for 2007 and 2008 were 5,093 GWh and 5,208 GWh, respectively.

[6] If the rate increase proposed in this Application is approved by the Board, the 2010 forecast sales growth will be reduced from 1.7% to 1.0%. This is a result of elasticity effects. See Section 5.2.2, *The Forecast*, p. 5-3 to 5-5.

Newfoundland Power, and a continuing high proportion of electric heating in new home construction.[7]

Forecast electricity sales and electricity revenue for 2009 and 2010E are based on the Company's May 2009 sales forecast.[8]

Table 3-2 shows other revenue from 2007 to 2010E.

Table 3-2
Other Revenue: 2007 to 2010E
($000s)

	2007	**2008**	**2009F**	**2010E**
Pole Attachment	8,568	8,861	9,172	9,365
Amortization of Municipal Tax ("MTA") Liability[9]	-	1,362	1,362	1,362
Customer Account Interest[10]	1,477	1,155	1,209	1,222
Miscellaneous[11]	1,852	1,889	2,261	1,851
Total	**11,897**	**13,267**	**14,004**	**13,800**

Pole attachment charges are the largest component of other revenue. The increase in pole attachment charges principally reflects increased joint-use of poles.[12]

[7] The proportion of new housing using electric heating was 83% in 2007 and 88% in 2008; and is forecast to be 86% in 2009 and 88% in 2010.

[8] The *Customer, Energy, and Demand Forecast* of May 2009 is found in *Volume 2: Supporting Materials, Tab 6.*

[9] The MTA is a 3-year amortization of a regulatory liability associated with timing differences in the recovery and payment of municipal taxes. It was approved in Order No. P.U. 32 (2007).

[10] Customer account interest is interest received on overdue electricity accounts. Prior to 2008, this interest was recorded as a reduction in finance charges. Commencing in 2008, customer account interest has been recorded as other revenue. For comparative purposes, 2007 customer account interest has been included as other revenue in Table 3-2.

[11] Miscellaneous revenue includes customer jobbing charges, wheeling charges, fees charged pursuant to the Company's regulations governing service, and other revenue amounts. For 2009, it also includes a $384,000 gain on the sale of property.

[12] In 2007, a total of 196,984 utility poles were jointly used by Newfoundland Power and telecommunications service providers. In 2010, a total of approximately 205,000 utility poles are forecast to be jointly used.

3.2.2 Power Supply Cost

Table 3-3 shows power supply cost from 2007 to 2010E.

Table 3-3
Power Supply Cost: 2007 to 2010E
($000s)

	2007	**2008**	**2009F**	**2010E**
Purchases from Hydro (Normalized)	326,359	334,006	344,155	353,726
Replacement Energy Cost[13]	(1,795)	598	598	598
Weather Normalization Reserve[14]	1,732	2,101	2,101	2,101
DMI Account[15]	-	641	-	-
Unit Cost Variances[16]	482	(688)	(688)	(688)
Power Supply Cost	**326,778**	**336,658**	**346,166**	**355,737**

Increases in power supply cost reflect increased purchases from Hydro to meet Newfoundland Power's customers' requirements. A portion of annual variances in power supply cost for the period 2008 through 2010E are deferred for recovery via operation of the Energy Supply Cost Variance clause.[17]

[13] In Order No. P.U. 39 (2006), the Board approved the deferred recovery of $1.8 million in replacement energy costs related to the Rattling Brook Hydro Plant refurbishment project. In Order No. P.U. 32 (2007) the Board approved amortization of this deferral in equal amounts over the period 2008 through 2010.

[14] In Order No. P.U. 19 (2003) the Board approved amortization of a $5.6 million non-reversing balance (on an after tax basis) in the Hydro Production Equalization component of this reserve over the period 2003 through 2007. In Order No. P.U. 32 (2007) the Board approved the amortization of a $6.8 million (on an after tax basis) non-reversing balance in the Degree Day component of this reserve over the period 2008 through 2012.

[15] The Demand Management Incentive ("DMI") account was approved by the Board in Order No. P.U. 32 (2007). In 2008, an amount of $641,000 reflecting reduced demand costs accrued to the DMI account. In Order No. P.U. 21 (2009), the Board approved refund of this amount to customers via the July 1, 2009 Rate Stabilization Adjustment.

[16] In Order No. P.U. 44 (2004) the Board approved the creation of the Purchased Power Unit Cost Variance Reserve. In Order No. P.U. 6 (2008) the Board approved the refund to customers, via the July 1, 2008 Rate Stabilization Adjustment, of a $482,000 balance accrued in the reserve for 2007. In Order No. P.U. 32 (2007), the Board approved the amortization of $2.1 million ($1.3 million on an after-tax basis) accrued in the reserve up to December 31, 2006, over the period 2008 to 2010.

[17] The Energy Supply Cost Variance clause effectively provides that annual variations from test year in the *energy* portion of power supply cost are deferred for recovery via the Rate Stabilization Adjustment in the succeeding years. This was approved by the Board in Order No. P.U. 32 (2007) in response to marginal supply cost dynamics on the Island interconnected grid.

3.2.3 Pension Costs

Table 3-4 shows Newfoundland Power's pension and early retirement program ("ERP") costs from 2007 to 2010E.

Table 3-4
Pension Costs: 2007 to 2010E
($000s)

	2007	**2008**	**2009F**	**2010E**
Pension	5,701	3,040	2,577	5,701

Pension costs decreased from 2007 to 2008 principally due to growth in pension plan assets in previous years, and a 0.25% increase in the discount rate used to value defined benefit pension obligations.[18]

Newfoundland Power pension costs are forecast to decrease from 2008 to 2009 principally due to a 2% increase in the discount rate used to value defined benefit pension obligations.[19] Pension costs in 2010E are forecast to increase over 2009 as a result of pension plan asset value losses experienced in 2008.[20]

[18] The discount rate is used to determine the present value of obligations related to the defined benefit pension plan. The discount rate increased from 5.25% in 2007 to 5.50% in 2008. This served to reduce pension expense in 2008 by approximately $0.7 million.

[19] The increase in discount rate for 2009 served to reduce 2009 pension expense; however the pension expense reduction was partly offset by lower expected returns on pension plan assets during the year. For further information on discount rates and pension plan asset performance see Section 3.4.2 *Pension Plans*, p. 3-21 *et. seq.*

[20] The defined benefit pension plan assets experienced a loss in value of approximately $41 million in 2008 due to market conditions. The difference between the expected return on pension plan assets and the actual return experienced in 2008 will be reflected in asset values over the period 2009 through 2011, and will serve to increase pension expense. The 2008 loss in asset value is not fully reflected in 2009 pension expense due to Newfoundland Power's use of the market-related method of valuing pension assets for the purposes of determining pension expense. Use of the market-related method creates a smoothing impact on pension expense, and thereby reduces the volatility caused by changing market conditions. The Company's use of the market-related method was approved by the Board in Order No. P.U. 19 (2003).

3.2.4 Depreciation

Table 3-5 shows depreciation and related cost recovery deferrals from 2007 to 2010E.

Table 3-5
Depreciation Expense: 2007 to 2010E
($000s)

	2007	**2008**	**2009F**	**2010E**
Depreciation[21]	39,955	40,649	41,852	43,338
Cost Recovery Deferrals[22]	(5,793)	-	-	-
Amortization of Deferred Cost Recoveries[23]	-	3,862	3,863	3,861
Net Depreciation Expense	**34,162**	**44,511**	**45,715**	**47,199**

Changes in net depreciation expense reflect a combination of continued investment in the electricity system; a decline in the composite depreciation rate from 3.5% to 3.4% commencing in 2008; and changes in deferrals and associated cost recoveries.

3.2.5 Finance Charges

Table 3-6 shows average debt, finance charges and average cost of debt for 2007 to 2010E.

Table 3-6
Finance Charges: 2007 to 2010E

	2007	**2008**	**2009F**	**2010E**
Average Debt ($000s)	430,924	440,841	453,950	479,623
Finance Charges ($000s)	33,462	33,507	34,917	36,211
Average Cost of Debt (%)	7.77	7.60	7.69	7.55

[21] Newfoundland Power's depreciation expense reflects depreciation rates for 2008 and subsequent years, as approved by the Board in Order No. P.U. 32 (2007). Newfoundland Power's depreciation expense for 2008 through 2010E is reduced by $174,000 annually as a result of a 4-year amortization of a depreciation true-up of $695,000 approved by the Board in Order No. P.U. 32 (2007).

[22] The cost recovery deferral in 2007 related to the 2005 expiration of a depreciation true up approved in Order No. P.U. 19 (2003). The cost recovery deferral was approved in Order No. P.U. 39 (2006).

[23] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of $11.6 million in cost deferrals related to depreciation over the period 2008 to 2010.

Finance charges are the cost of debt used to finance investment in regulated assets. Finance charges are composed primarily of interest on first mortgage sinking fund bonds ("First Mortgage Bonds") and short-term borrowings.[24]

Newfoundland Power's average debt increases in the period from 2007 to 2010E due to continued investment in the electricity system required to provide service to customers.

The average cost of debt from 2007 through 2010E is relatively stable. Lower 2008 average cost of debt was a result of refinancing First Mortgage Bonds and a reduction in short-term interest rates.[25] The average cost of debt is forecast to increase in 2009 primarily due to a May 2009 issuance of $65 million of First Mortgage Bonds.[26] For 2010, the lower average cost of debt principally reflects forecast higher short term debt balances.[27]

---

[24] Finance charges also reflect amounts related to amortization of debt issue costs and allowance for funds used during construction.

[25] Newfoundland Power repaid approximately $4.6 million of outstanding long-term debt in each of 2007 and 2008 in accordance with the sinking fund provisions associated with outstanding First Mortgage Bonds. In addition, approximately $31.5 million in 11.9% First Mortgage Bonds were refinanced in the third quarter of 2007 with proceeds from a 5.9% First Mortgage Bond issue. The Company's average short-term borrowing rates in 2008 were approximately 3.8%, as compared to 5% in 2007.

[26] The $65 million in First Mortgage Bonds were issued at 6.61%. Forecast average short-term borrowing rates for 2009 are 1.36%.

[27] The Company's forecast average short-term interest rate for 2010 is 2%. Forecast year-end short-term borrowings are approximately $28.7 million for 2010E, compared to approximately $3.9 million for 2009.

3.2.6 Income Taxes

Table 3-7 shows the Company's income taxes from 2007 to 2010E.

Table 3-7
Income Taxes: 2007 to 2010E[28]

	2007	2008	2009F	2010E
Income Taxes[29] ($000s)	12,668	19,677	16,683	13,132
Effective Income Tax Rate[30](%)	28.6	36.8	32.8	32.6

Newfoundland Power's effective income tax rate increased from 2007 to 2008 principally due to tax effects associated with regulatory amortizations and cost deferrals, and the adoption of the accrual method of accounting for income tax related to pension costs starting in 2008.[31]

The Company's effective income tax rate is forecast to decrease in 2009 and 2010E due to reductions in the statutory corporate income tax rate and the 2008 conclusion of payments required under the 2005 income tax settlement.[32]

[28] Income taxes exclude the effect of non-regulated operating costs. These tax effects were $492,000 in 2007 and $531,000 in 2008. They are forecast to be $513,000 in 2009 and $548,000 in 2010.

[29] Income taxes in 2007 include $2.7 million related to the 2005 tax settlement. Income taxes in 2008 include $2.5 million related to the 2005 tax settlement. In Order Nos. P.U. 39 (2006) and P.U. 32 (2007) the Board authorized Newfoundland Power to recognize an amount of 2005 unbilled revenue equal to the forecast taxes payable pursuant to the 2005 tax settlement in 2007 and 2008, respectively.

[30] Includes the effects of 2005 tax settlement. Excluding the effects of the 2005 tax settlement, the effective income tax rates would be 23.7% in 2007 and 33.6% in 2008.

[31] In Order No. P.U. 32 (2007) the Board approved the adoption of the accrual method of accounting for income tax related to pension costs. Prior to 2008, the difference between pension funding and pension expense served to reduce income taxes in that year. Adopting accrual accounting for income tax relating to pension costs for regulatory purposes resulted in recognizing both the costs of the benefits and the related income tax effects of those costs in the same period.

[32] The statutory tax rate in 2009 is 33% and in 2010 is 32%. In 2008, Newfoundland Power paid the final instalment of $2.5 million related to the 2005 tax settlement.

3.2.7 Returns

Table 3-8 shows the Board approved rates of return on rate base, the actual and forecast rates of return on rate base, and the actual and forecast rates of return on common equity for the period 2007 to 2010E.

Table 3-8
Rates of Return: 2007 to 2010E
(%)

	2007	**2008**	**2009F**	**2010E**
Return on Rate Base				
Midpoint (Approved)	8.47	8.37	8.37	8.10
Actual / Forecast	8.07	8.20	8.15	7.27
Return on Common Equity	8.66	9.13	8.88	6.87

Newfoundland Power's actual rates of return on rate base for 2007 and 2008 are below the Board-approved midpoint used for rate setting purposes.[33] The actual rates of return achieved were lower principally due to a combination of higher than forecast rate base growth and lower than forecast short-term interest costs. The Company's return on rate base for 2009 is also forecast to be below the Board-approved midpoint used for rate setting purposes.[34]

[33] Newfoundland Power's midpoint (approved) rate of return on rate base for 2007 and 2008 were set by the Board in Order Nos. P.U. 40 (2006) and P.U. 32 (2007), respectively.

[34] The midpoint (approved) rate of return on rate base for 2009F reflects operation of the automatic adjustment formula, as approved by the Board in Order No. P.U. 35 (2008). The operation of the formula for 2009 resulted in a calculated return on rate base of 8.25%, which is within the range of return on rate base approved by the Board in Order No. P.U. 32 (2007). As a result, there was no change to Newfoundland Power's approved rate of return on rate base for 2009.

The forecast midpoint rate of return on rate base for 2010E reflects forecast operation of the Formula for 2010E, based on averaging observed *ask yields* for the three most recent series of long-term Government of Canada bonds as at May 1, 2009.[35]

Newfoundland Power's 2010E rate of return on rate base is forecast to be 7.27% and its rate of return on equity is forecast to be 6.87%.

3.3 CREDITWORTHINESS

The maintenance of public utility creditworthiness is one of the policy objectives set out in the Electrical Power Control Act, 1994. Continued creditworthiness is consistent with the least cost provision of service to customers.

This section of the evidence reviews Newfoundland Power's sources of credit, credit ratings, and credit metrics. It also reviews the financial targets necessary to maintain the Company's current investment grade credit ratings.

In this Application, Newfoundland Power is proposing a common equity component of capital structure of 45% and a rate of return on common equity of 11% for ratemaking purposes in 2010. These proposals should maintain the Company's current investment grade credit ratings. The increased rate of return on common equity of 11% will require an increase of approximately 2.0% in 2010 customer rates.

[35] The average observed ask yield as at May 1, 2009 was 3.86% based on the following observations: (i) 3.85% (Government of Canada 4.0% Series due 2041); (ii) 3.83% (Government of Canada 5.0% Series due 2037); and (iii) 3.91% (Government of Canada 5.75% Series due 2033). Operation of the automatic adjustment formula based on an average long-term Government of Canada bond yield of 3.86% results in a rate of return on equity of 8.36%. Using this 8.36% cost of common equity, and the average capital structure approved by the Board in Order No. P.U. 32 (2007), results in a calculated rate of return on rate base (weighted average cost of capital) of 8.10%.

In this Application, Newfoundland Power is also proposing discontinuing use of the automatic adjustment formula (the "Formula") for establishing its annual rate of return on rate base in years subsequent to a test year. This is in response to materially changed financial market conditions.

3.3.1 Sources of Credit

Newfoundland Power has two primary sources of credit. They include First Mortgage Bonds and short-term credit facilities.

As of year-end 2008, Newfoundland Power had approximately $409 million of First Mortgage Bonds outstanding.[36] The Company's ability to issue First Mortgage Bonds is dependent on the availability of earnings to pay interest on any additional bonds.[37]

The Company has a stand-alone, 3-year $100 million committed credit facility agreement with a syndicate of Canadian banks.[38] Committed credit facilities provide greater certainty of credit availability for the Company. The Company also has a $20 million demand facility to support short-term cash requirements.[39]

[36] The $409 million in First Mortgage Bonds mature over the period 2014 through 2037. Accordingly, no requirement for Newfoundland Power to refund existing First Mortgage Bonds exists until 2014.

[37] The Company's Trust Deed that secures its First Mortgage Bonds requires, in effect, a Trust Deed interest coverage of 2.0 times or higher for the Company to issue additional bonds to finance its rate base. The Company's 2010E Trust Deed interest coverage is 2.1 times. This is near the bottom of the range at which the Company can issue additional First Mortgage Bonds.

[38] The current maturity date of this facility is August 29, 2011. The Company was originally authorized to enter into this facility by Order No. P.U. 1 (2005). Further amendments to extend the term of the facility were authorized by Order Nos. P.U. 4 (2006) and P.U. 22 (2008).

[39] This facility effectively supports very short-term (i.e., day-to-day) credit requirements.

On May 25, 2009, Newfoundland Power issued $65 million in First Mortgage Bonds at an interest rate of 6.61%. The credit spread associated with this issue of First Mortgage Bonds was materially higher than previous issues.[40] The 6.61% interest rate was based on a credit spread of 2.75% over 30-year Government of Canada bonds. This compares to credit spreads associated with First Mortgage Bond issues of 1.40% in 2007 and 1.06% in 2005. The 2009 increased credit spread reflects current financial market conditions.

3.3.2 Credit Ratings

An investment grade credit rating allows Newfoundland Power to have access to capital markets at reasonable cost.

The most recent credit rating reports from Dominion Bond Rating Service ("DBRS") and Moody's Investors Services ("Moody's") are found in Exhibit 4. Both DBRS and Moody's assess the Company's creditworthiness on a stand-alone basis.

Table 3-9 shows DBRS and Moody's current credit ratings for Newfoundland Power.

Table 3-9
Credit Ratings

Rating Agency	Rating
DBRS	A, Stable
Moody's	Baa1, Stable

Newfoundland Power's current credit ratings are investment grade.

[40] First Mortgage Bond issues are priced based upon a 30-year Government of Canada bond yield plus an additional amount, or *credit spread*, to compensate debt holders for the additional risk in holding a Newfoundland Power bond. The *credit spread* is dependent on many factors, including credit quality of the issuer and prevailing market conditions at the time of sale.

Moody's and DBRS evaluate qualitative and quantitative data including a number of credit metrics in establishing the Company's credit rating. The key credit metrics are pre-tax interest coverage,[41] cash flow interest coverage[42] and cash flow debt coverage.[43]

Pre-tax interest coverage measures the Company's ability to meet its interest obligations through its reported earnings. Traditionally, the Board has considered pre-tax interest coverage to be a primary indicator of creditworthiness in evaluating the relationship between capital structure, rate of return on common equity and interest coverage.[44]

In recent years, credit rating agencies have placed more emphasis on cash flow metrics in their assessment of regulated utilities.[45] This is because principal and interest obligations can only be paid from cash flows. Regulated earnings will not always fully mirror cash flows.[46]

[41] Pre-tax interest coverage is earnings before interest and income taxes, divided by interest. Interest includes the amortization of deferred debt issue costs.

[42] Cash flow interest coverage is cash flow from operations, divided by interest. Cash flow from operations is the amount shown on the Company's statements of cash flows excluding the change in non-cash working capital, less (i) dividends on preferred shares, and (ii) the difference between pension expense and pension funding for current service costs.

[43] Cash flow debt coverage is cash flow from operations, divided by the sum of total debt and preferred shares.

[44] See, for example, Order No. P.U. 16 (1998-99) at p.40-41, Order No. P.U. 36 (1998-99) at p.44,84-85 and Order No. P.U. 19 (2003) at p.53-54.

[45] For example, cash flow interest coverage and cash flow debt coverage are central in the Moody's March 6, 2009 credit opinion of Newfoundland Power.

[46] For example, in 2010 the Company will recognize $4.6 million in 2005 unbilled revenue. However, because the 2005 unbilled revenue is an accounting accrual as opposed to cash, the impact of the 2010 accrual will be reflected in Newfoundland Power's 2010 earnings but not in its 2010 cash flows.

Table 3-10 shows the Company's credit metrics from 2007 to 2010E.

Table 3-10
Credit Metrics: 2007 to 2010E

	2007	**2008**	**2009F**	**2010E**
Pre-tax Interest Coverage (times)	2.2	2.5	2.4	2.0
Cash Flow Interest Coverage (times)	2.6	3.1	3.1	2.8
Cash Flow Debt Coverage (%)	12.6	15.8	15.9	13.0

The Company's credit metrics are expected to deteriorate in 2010E.

Pre-tax interest coverage is forecast to decline from 2.5 times in 2008 and 2.4 times in 2009, to 2.0 times in 2010E. Cash flow interest coverage is forecast to decline from 3.1 times in 2008 and 2009, to 2.8 times in 2010E. Cash flow debt coverage is expected to decline from 15.8% in 2008 and 15.9% in 2009, to 13.0% in 2010E.[47]

The forecast deterioration in credit metrics in 2010E is a result of declining forecast returns.

3.3.3 Financial Targets

Capital Structure and Rate of Return on Common Equity

Capital structure is the mix of debt and equity invested in a company, with debt representing the investment of bondholders, or other debt holders, and equity representing the investment of shareholders.

[47] In its March 6, 2009 Credit Opinion, Moody's indicated that Newfoundland Power's credit metrics were slightly weaker than those of its Baa1-rated peers. Moody's anticipated Newfoundland Power's cash flow interest coverage would stay above 3 times going forward and cash flow debt coverage would remain in the 15% to 16% range. (See Exhibit 4).

Table 3-11 shows the targeted capital structure of Newfoundland Power.

Table 3-11
Targeted Capital Structure

Debt	54%
Preferred Equity	1%
Common Equity	45%

Credit rating agencies have consistently cited Newfoundland Power's capital structure, which includes 45% common equity, as a major strength that mitigates the risk associated with its small size and relatively low forecast growth estimates.[48] The Company's target of 45% common equity in its capital structure is consistent with Board orders since 1990.[49]

In this Application, Newfoundland Power is targeting a 2010 rate of return on common equity of 11% for ratemaking purposes.[50] A 2010 increase in the rate of return on common equity for ratemaking purposes from current levels to 11% will require an increase of approximately 2.0% in 2010 customer rates.[51]

A common equity component of capital structure of 45%, together with a rate of return on common equity of 11%, will provide Newfoundland Power the opportunity to improve its forecast 2010 credit metrics and maintain its investment grade credit ratings.

---

48 See, for example, the DBRS Credit Rating Report (May 1, 2008), p. 1-2 provided in Exhibit 4.

49 See Order Nos. P.U. 1 (1990), P.U. 6 (1991), P.U. 7 (1996-97), P.U. 16 (1998-99), P.U. 19 (2003), and P.U. 32 (2007).

50 See *Opinion on Capital Structure and Fair Return on Equity*, found in *Volume 2: Supporting Materials, Tab 10.*

51 11% minus 8.95% (2009 ratemaking return) equals 2.05%. 2.05% times $386,307,000 (2010 average book equity) equals $7,919,294. $7,919,294 divided by 0.68 percent (1 – tax rate) equals $11,646,020. $11,646,020 divided by $568,731,000 (2010E customer charges from Exhibit 10) equals 2.0%.

Forecast 2010 Credit Metrics

The relationship between capital structure and rate of return on common equity is arithmetic. As the common equity component of capital structure varies, the rate of return on common equity required to reach investment grade credit metrics will correspondingly vary.

Exhibit 5 shows the relationship between the Company's capital structure, the rate of return on common equity and credit metrics on a forecast 2010 basis.

In this Application, Newfoundland Power is proposing to commence recognition of other post employment benefits ("OPEBs") on an accrual basis commencing in 2010.[52] This proposal has an impact on the Company's forecast 2010 credit metrics. Accordingly, Exhibit 5 illustrates the relationship between the Company's capital structure, the rate of return on common equity and credit metrics for 2010 on both the cash basis and accrual basis of accounting for OPEBs.[53]

The adoption of accrual accounting for OPEBs will increase the Company's cash flow from operations, thereby improving its credit metrics, particularly cash flow metrics. The improvement in metrics reflects the fact that OPEBs costs will be recovered from customers in advance of the Company's requirement to pay for the related benefits. This recovery also serves to reduce the Company's financing requirements.[54]

---

[52] The Company's OPEBs proposal is reviewed in Section 3.4.3 *Other Post-Employment Benefits* at p. 3-27

[53] Page 1 of Exhibit 5 indicates the relationship assuming no change in OPEBs accounting in 2010. Page 2 of Exhibit 5 indicates the relationship assuming the adoption of the accrual method of accounting for OPEBs in 2010.

[54] The cumulative difference between the costs recovered from customers and the actual OPEBs payments will be treated as a reduction in rate base. This will reduce the rate base financing costs required from customers.

Table 3-12 shows forecast 2010 credit metrics under three scenarios. They include: (i) the Company's existing scenario; (ii) approval of the proposals contained in this Application, including adoption of accrual accounting for OPEBs in 2010; and (iii) approval of the proposals in this Application except adoption of accrual accounting for OPEBs in 2010 (called "Cash OPEBs").

Table 3-12
Impact of OPEBs
Forecast 2010 Credit Metrics

	2010E	**2010F**	
		Accrual OPEBs	**Cash OPEBs**
Pre-tax Interest Coverage (times)	2.0	2.7	2.7
Cash Flow Interest Coverage (times)	2.8	3.5	3.4
Cash Flow Debt Coverage (%)	13.0	18.9	18.0

Forecast 2010 cash flow credit metrics will improve as a result of the Company's adoption of accrual accounting treatment for OPEBs.

3.3.4 The Automatic Adjustment Formula

The Formula is used to adjust the Company's rate of return on rate base and customer rates in years subsequent to a test year.[55]

In Order No. P.U. 32 (2007), the Board approved continued use of the Formula for not more than three years following 2008, with modifications to reflect adoption of the Asset Rate Base Method for calculating rate base. Since Order No. P.U. 32 (2007), financial market conditions

[55] The Formula was originally established pursuant to Order Nos. P.U. 16 (1998-99) and P.U. 36 (1998-99). Continued use of the Formula was approved in Order Nos. P.U. 19 (2003) and P.U. 32 (2007).

have materially changed. These changing conditions have, in turn, affected the fairness of the returns on equity yielded by use of the Formula.[56]

In this Application, Newfoundland Power seeks a return on equity for ratemaking purposes of 11% for 2010. This compares to a forecast 2010 return on equity for ratemaking purposes of 8.36% resulting from continued use of the Formula.[57]

Given current financial market conditions, this Application proposes discontinuing use of the Formula for the adjustment of the Company's rate of return on rate base and customer rates in years subsequent to the 2010 test year.

3.4 EMPLOYEE FUTURE BENEFITS

Newfoundland Power has pension and other post employment benefit plans that provide its employees with benefits upon retirement.

This section of the evidence provides an overview of the Company's employee future benefit plans and accounting policies for those plans. It also reviews how recent financial market conditions have affected the costs associated with Newfoundland Power's defined benefit pension plan.

In this Application, Newfoundland Power is proposing the creation of a regulatory mechanism to ensure the fair recovery of pension expense in current financial market conditions.

[56] This matter is considered fully in the *Opinion on Capital Structure and Fair Return on Equity*, found in *Volume 2: Supporting Materials, Tab 10.*

[57] See footnote 35.

In this Application, Newfoundland Power is proposing to commence the accrual method of accounting for other post employment benefits in 2010. To implement this proposal for accounting for employee future benefits will require a customer rate increase of approximately 1.0 % in 2010.

3.4.1 Newfoundland Power Employee Future Benefits

Newfoundland Power maintains plans for its employees which provide for benefits upon retirement. These plans fall into two broad categories: pension plans and other post employment benefit plans.

The Company maintains both defined benefit and defined contribution pension plans. Defined benefit plans typically provide retirement income based upon an employees' pay and years of service at the time of retirement.[58] Defined contribution plans provide retirement income based upon the contributions made by the Company and the employee together with accrued returns on those contributions.[59] Since May 2004, Newfoundland Power's defined benefit pension plan has been closed to new entrants.

The OPEBs provided by the Company to its employees include retirement allowances payable on retirement[60] and health, medical and life insurance for retirees and their dependents.

---

[58] Newfoundland Power's principal pension plan is its defined benefit pension plan, which was created in 1984. There are currently 492 active employees participating in this plan. In addition, at December 31, 2008 the defined benefit pension plan provided retirement income to a total of 660 retirees and their survivors.

[59] Defined contribution pension arrangements have become more common in recent years as defined benefit pension arrangements have become less common. This development results in a shift of pension investment return risk from employers (in defined benefit plans) to employees (in defined contribution plans). It also results in increased pension portability as defined contribution plans typically have segregated employee benefit accounts.

[60] Retirement allowances are 1 week's salary per year of service up to a maximum of 23 weeks allowance.

3.4.2 Pension Plans

Market Conditions

Financial market conditions affect defined benefit pension plans in two fundamental ways. The first relates to the *actual* value of assets held in a plan. Changes in asset values resulting from market conditions impact both the funding obligations and the accounting for the expense associated with defined benefit pension plans. The second relates to the valuation of *future* obligations in accounting for the expense associated with defined benefit pension plans. Discount rates used to present value future plan obligations are required by accounting standards to reflect prevailing financial market conditions.[61]

Like virtually all Canadian defined benefit pension plans, Newfoundland Power's plan experienced a material loss in asset value in 2008 as a result of market conditions. This loss in asset value will impact both Newfoundland Power's future funding obligations for the defined benefit pension plan and future pension expense.

The financial market conditions which commenced in 2008 have also given rise to increased volatility in the discount rate used to present value future plan obligations for accounting purposes. This increased volatility has increased the uncertainty associated with forecasting future pension expense.

[61] Accounting standards governing the discount rate to be used to present value future plan obligations effectively requires the discount rate to reflect market conditions at the end of a fiscal year. This differs from actuarial practice which governs pension plan funding. The discount rates used to present value future plan obligations for purposes of funding reflect assumptions prescribed by actuarial practice.

Pension Plan Asset Performance

At December 31, 2008, Newfoundland Power's defined benefit pension plan held assets of approximately $213 million. This reflects a loss in asset value of approximately $41 million or 16% of total fund assets in 2008. This loss has an effect on both Newfoundland Power's accounting for pension expense and its plan funding obligations.

Table 3-13 shows Newfoundland Power's defined benefit and defined contribution pension expense from 2007 to 2011F.[62]

Table 3-13
Pension Expense
2007 to 2011F
($000s)

	2007	**2008**	**2009F**	**2010F**	**2011F**
Defined Benefit Pension Plans[63]	4,550	2,045	1,505	4,586	8,016
Defined Contribution Pension Plans	1,151	995	1,072	1,115	1,159
Total Pension Expense	**5,701**	**3,040**	**2,577**	**5,701**	**9,175**

Newfoundland Power's pension expense is expected to increase to approximately $5.7 million in 2010 compared to $2.6 million in 2009. The Company's 2011 pension expense is expected to increase further to approximately $9.2 million. These increases primarily reflect the increase in pension expense resulting from the 2008 loss in asset value experienced in the Company's defined benefit pension plan.[64]

---

[62] Pension expense for Newfoundland Power's defined benefit pension plans reflects estimates with respect to matters such as the expected performance of pension plan assets, future salary escalation and the retirement ages of employees. Newfoundland Power recognizes pension expense on an accrual basis.

[63] Includes amounts under the Company's legacy pension uniformity plan which has no active members.

[64] The 2008 loss in asset value is not fully reflected in 2009 pension expense due to Newfoundland Power's use of the market-related method of valuing pension assets for the purposes of determining pension expense. See footnote 20.

Newfoundland Power’s future pension funding obligations are also impacted by the loss in pension plan asset value in 2008. Funding requirements for the Company’s defined benefit pension plan is an actuarially determined amount that, when combined with employee contributions, is expected to be sufficient to satisfy future benefit payments as they become due. The two components of pension funding are current service funding and special funding.[65]

Newfoundland Power’s actuaries completed an actuarial valuation of the Company’s defined benefit pension plan as at December 31, 2008 (the “2008 Pension Valuation”).[66] The 2008 Pension Valuation is found in *Volume 2: Supporting Materials, Tab 3.*

The 2008 Pension Valuation indicates that as of December 31, 2008 the defined benefit pension plan had a funding excess of approximately $10.4 million on a going-concern basis,[67] and a funding deficiency of approximately $6.9 million on a solvency basis.[68] As a result of the 2008 Pension Valuation, Newfoundland Power expects to make annual special funding payments of approximately $1.5 million from 2009 through 2013.[69]

---

65 Current service funding is related to service rendered by active employees in the current year. Special funding represents additional funding required to satisfy additional pension costs related to unfunded pension liabilities such as those associated with early retirement programs or the solvency deficiency identified in the 2008 Pension Valuation.

66 Pension legislation requires that funding be based on actuarial valuations that are to be conducted, at a minimum, once every three years. The most recent actuarial valuation of Newfoundland Power’s defined benefit pension plan was as of December 31, 2008. The previous actuarial valuation was as of December 31, 2005.

67 Valuation of a defined benefit pension plan on a going-concern basis values the plans assets and liabilities as though the plan would be maintained until all retirement benefit obligations have been met.

68 Valuation of a defined benefit pension plan on a solvency basis values the plans assets and liabilities as though the plan were wound up and settled on the valuation date. For the purposes of Newfoundland Power’s defined benefit pension plan, the circumstances in which the plan wind-up is assumed to take place is Newfoundland Power ceasing to operate.

69 This is required to fund the identified solvency deficiency. The solvency deficiency of $6,933,000 divided by 5 years plus interest of $161,000 per year.

Table 3-14 compares pension expense and pension funding associated with Newfoundland Power's defined benefit pension plan for the period 2009 through 2011F.[70]

Table 3-14
Pension Expense and Pension Funding
2009 to 2011F
($000s)

	2009F	2010F	2011F
Pension expense	1,505	4,586	8,016
Pension funding	4,866	4,999	5,137

Forecasting Pension Expense

A principal variable in determining pension expense is the discount rate used to value future pension obligations. This discount rate reflects year end financial market conditions.[71]

Table 3-15 shows the discount rate used to calculate the pension expense associated with Newfoundland Power's defined benefit pension plan for 2006 through 2009.

Table 3-15
Defined Benefit Pension Discount Rate
2006 to 2009

	2006	2007	2008	2009
Discount Rate (%)	5.25	5.25	5.50	7.50

Changes in the discount rate can result in large differences in pension expense from year to year and can result in material differences from forecast. In general, for a defined benefit pension

[70] Differences between annual pension expense and annual pension funding are reflected in deferred assets. In Order No. P.U. 19 (2003) the Board ordered that deferred assets be included in the Company's rate base. In years where pension funding exceeds pension expense, the difference serves to increase rate base. Conversely, in years where pension expense exceeds pension funding, the difference serves to reduce rate base.

[71] The discount rate used to value pension obligations is prescribed by accounting standards. The discount rate for pension expense purposes for Newfoundland Power is the trading yield, as at December 31 of the previous year, of high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. As at December 31, 2008, the average duration of these bonds was approximately 14 years and the trading yield was approximately 7.5%.

plan, a higher discount rate tends to lower pension expense and a lower discount rate tends to increase pension expense.

From 2006 through 2008, the discount rate used to value the Company's pension obligations for expense purposes was relatively stable. From 2008 to 2009, the discount rate increased by 2%. This increase was reflective of the volatile market conditions which also impacted asset values.

Table 3-16 shows the estimated pension expense associated with Newfoundland Power's defined benefit pension plan for 2010 through 2012, calculated based on a range of discount rates from 5.50% to 8.50%.

Table 3-16
Defined Benefit Pension Expense
2010E to 2012E
($000s)

Discount Rate (%)	2010E	2011E	2012E
5.50%	10,849	14,147	13,941
6.00%	9,117	12,426	12,215
6.50%	7,411	10,863	10,611
7.00%	5,852	9,295	9,035
7.50%	4,424	7,858	7,589
8.00%	3,117	6,540	6,263
8.50%	2,173	5,306	5,020

A change in the discount rate used to value pension obligations of +/- 1% will vary Newfoundland Power's pension expense in the next year by approximately +/- $2.3 to $3.4 million.[72]

[72] By comparison, a 2010 allowed range of return on rate base of +/- 18 basis points is approximately +/- $2.3 million before tax.

The variability of pension expense is not reasonably predictable in current volatile financial market conditions.[73] The discount rate that will be used to determine *actual* pension expense for 2010 will not be known until the end of 2009.[74] As a result, the actual pension expense for 2010 may differ materially from that estimated 6 months prior to year end.[75]

The uncertainty of pension expense forecasting in current financial market conditions presents potential risks for both the Company and its customers. On one hand, a 1% increase in the discount rate used to calculate pension expense could result in the Company achieving earnings in excess of its allowed return solely due to fluctuations in pension expense.[76] On the other hand, a 1% decrease in the discount rate could result in the Company not having a reasonable opportunity to earn its allowed return solely due to fluctuations in pension expense.[77]

In these circumstances, the creation of a regulatory mechanism to ensure the reasonable recovery of actual pension expense is justified. In this Application, Newfoundland Power proposes the creation of a Pension Expense Variance Deferral Account to effectively provide for the recovery of only that pension expense actually incurred by the Company.[78]

---

73 This lack of predictability was particularly evident in the fourth quarter of 2008. At September 30, 2008, the observed trading yield of high quality bonds prescribed by accounting standards for calculating 2009 pension expense was 6.75%. At December 31, 2008, the observed trading yield was 7.50%. The variability in discount rates experienced in the fourth quarter of 2008 was reflective of the financial market conditions that contributed to a 2% overall increase in the discount rate in 2008 to 2009. By comparison, the average year-over-year change in discount rate from 2000 (the 1st year to which the current accounting standards applied) through 2008 was +/- 0.32%.

74 This is because the discount rate used in the pension expense calculation is an observed year-end trading yield.

75 In this Application, the Company has used a discount rate of 7.5% to calculate the estimate of 2010 pension expense.

76 This result reflects that the impact of a 1% increase in the discount rate would reduce pension expense by approximately $2.3 to $3.4 million. This amount meets or exceeds the historical +/- 18 basis points allowed range of return on rate base, which translates into approximately +/- $2.3 million in 2010.

77 This result reflects that the impact of a 1% decrease in the discount rate would increase pension expense by approximately $2.3 to $3.4 million.

78 Adjustment for variations between estimated test year pension expense and actual pension expense is proposed to be achieved through the Rate Stabilization Account (“RSA”). Section II 6 of the RSA, which provides that “The RSA shall be adjusted by any other amount as ordered by the Board”, would permit such an adjustment were the Board to order it.

The proposed Pension Expense Variance Deferral Account is provided in Exhibit 9.

3.4.3 Other Post-Employment Benefits

Currently, Newfoundland Power recognizes costs associated with OPEBs on a cash basis as opposed to an accrual basis.[79] The cash cost of OPEBs in 2010 is forecast to be $1.7 million. The accrued cost of OPEBs in 2010 is forecast to be $7.4 million.[80]

In Order No. P.U. 19 (2003), the Board ordered the Company to file a report with its next general rate application which addresses the use of the accrual method as an alternative to the existing accounting treatment for OPEBs.[81] A current report on Employee Future Benefits, including a proposal for the adoption of the accrual method of accounting for OPEBs commencing in 2010 is found in *Volume 2: Supporting Materials, Tab 4*. Accrual accounting for OPEBs costs is the mainstream regulatory practice in Canada.[82] Accrual accounting for OPEBs is also consistent with the Company's accounting for pensions.

In this Application, Newfoundland Power proposes to adopt the accrual method of accounting for OPEBs costs for regulatory purposes effective January 1, 2010.

---

79 Practically, this means the Company only recognizes as a cost, the actual amount *paid* for OPEBs each year. Recognizing OPEBs costs on an accrual basis means recognizing as a cost in a year all current and future obligations *accrued* in that year, as estimated by the Company's actuary.

80 The current actuarial valuation of the Company's OPEBs obligations on an accrual basis is found in *Volume 2: Supporting Materials, Tab 5*. As at December 31, 2008, Newfoundland Power's OPEBs obligations to employees were valued at $59.6 million on an accrual basis.

81 In Order No. P.U. 19 (2003), the Board stated its concern about the potential liability for OPEBs and was of the view that Newfoundland Power should explore using the accrual method of accounting for these benefits. In its 2008 General Rate Application, Newfoundland Power originally proposed to adopt the accrual method of accounting for OPEBs in 2008. As a result of the settlement agreement reached on issues in the 2008 General Rate Application, it was agreed that Newfoundland Power continue using the cash basis of accounting for OPEBs. This was approved by the Board in Order No. P.U. 32 (2007). In the settlement agreement it was specifically provided that the matter of OPEBs accounting would be further considered by the Board at Newfoundland Power's next General Rate Application.

82 Based upon the results of the survey, 22 utilities use the accrual method, including Hydro.

Table 3-17 shows forecast 2010 OPEBs costs calculated on the cash basis and accrual basis of accounting.

Table 3-17
2010 OPEBs Costs
($000,000s)

Cash Method	1.7
Accrual Method	7.4
Difference	**5.7**

OPEBs costs will increase by $5.7 million in 2010 if the Company adopts the accrual method of accounting for OPEBs as proposed in this Application.[83]

Transitional Matters

There are significant transitional obligations associated with this change in accounting policy. In 2003, the Board directed the Company to propose a plan to move to the accrual method of accounting for OPEBs that addresses the transitional obligations with a view to fulfilling Newfoundland Power's obligation to its employees while at the same time moderating its impact on customer rates. [84]

The transitional obligation associated with the Company's adoption of the accrual method of accounting for OPEBs in 2010 is $46.2 million.[85]

[83] The 2010 revenue requirement impact of the proposal is $5.6 million. The difference relates to a combination of tax and rate base effects. See R*eport on Other Post Employment Benefits, Volume 2: Supporting Materials, Tab 4*, at p.13, Table 8.

[84] See Order No. P.U. 19 (2003) at p.82-83.

[85] If the Company adopts the accrual method of accounting for OPEBs in 2010 as proposed in this Application, this $46.2 million legacy transitional obligation will not change. Effective January 1, 2000, the Canadian Institute of Chartered Accountants recommended the adoption of the accrual method of accounting for OPEBs. $46.2 million represents, in effect, the difference between use of the cash and accrual methods of accounting for OPEBs for the period 2000 to 2009.

Newfoundland Power is proposing that the disposition of this legacy transitional obligation be addressed at a future Company general rate proceeding. This will allow for an effective *phasing in* of the recovery of accrued OPEBs liabilities which, in turn, will help to moderate the immediate impact of the accounting change on customer rates.[86]

Newfoundland Power's OPEBs proposal, if approved by the Board, will result in current recovery of accrued OPEBs costs commencing in 2010. Addressing the legacy transitional obligation at a future time is a measured overall approach to dealing with this matter.[87]

3.5 INTERNATIONAL FINANCIAL REPORTING STANDARDS

Effective January 1, 2011, it is expected that Newfoundland Power will be required to comply with International Financial Reporting Standards ("IFRS")

This section of the evidence reviews the current status of IFRS transition, including the preeminent outstanding issue which relates to the future accounting treatment of regulatory assets and liabilities.

[86] For Newfoundland Power to fully address its OPEBs obligations, including the legacy transitional obligation in 2010, would result in an increase in 2010 revenue requirements of approximately 1.8% (see: *Report on Other Post Employment Benefits, Volume 2: Supporting Materials, Tab 4,* p.2). Implementing Newfoundland Power's employee future benefits proposals in this Application will result in an increase in 2010 revenue requirements of approximately 1%.

[87] While the impact of the recovery of the legacy transitional obligation on customer rates will only be determinable at the time the matter is addressed, the approximate rate impacts can be estimated. For example, for a 5-year amortization of the $46.2 million, the estimated rate impact (based on 2010E forecast revenue from rates of $568,731,000) would be approximately 1.6 %. A 10-year amortization would result in an estimated rate impact of approximately 0.8%. In 1992, the U.S. Financial Accounting Standards Board considered that the appropriate limits for (i) adopting accrual accounting should not exceed approximately 5 years, and (ii) deferred recovery of transitional amounts should not exceed approximately 20 years.

In this Application, Newfoundland Power is seeking the Board's approval that its next depreciation study relate to plant in service as at December 31, 2009. This will facilitate Newfoundland Power's transition to IFRS.

3.5.1 General

IFRS is a collection of financial reporting standards developed by the International Accounting Standards Board ("IASB"), an independent accounting standards-setting organization.[88] In 2006, the Canadian Accounting Standards Board ("AcSB") announced that, effective January 1, 2011, all publicly accountable enterprises would be required to comply with IFRS.[89] Newfoundland Power is one of the approximately 4,500 publicly accountable enterprises in Canada affected by this change.

The adoption of IFRS will be the most fundamental change in accounting standards in Canadian history. Once IFRS has been adopted, it will effectively be Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). Accordingly, the transition involves a detailed review of both the accounting standards which currently apply to Newfoundland Power and those that will apply in the future.[90]

For regulated utilities in Canada, the preeminent outstanding issue associated with the transition to IFRS is the future accounting treatment of regulatory assets and liabilities.

---

[88] IFRS have been adopted by over 100 countries including all those of the European Union. The U.S. has not adopted IFRS.

[89] The AcSB is the Canadian functional equivalent of the IASB. The AcSB establishes Canadian Generally Accepted Accounting Principles ("GAAP").

[90] The IFRS continue to evolve. As of January 1, 2008, IFRS included 37 separate standards. It was expected that 19 of these would change through the Canadian transition. This evolutionary feature adds a level of complication to the overall transition. See: *The CICA's Guide to IFRS in Canada.*

3.5.2 Regulatory Assets and Liabilities

Regulatory Assets and Liabilities Generally

Regulatory assets and liabilities are typically created in cost of service regulation by timing differences that reflect the economic impact of regulatory decision making.

A regulatory asset typically arises as a result of a timing difference between incurrence of a cost by a utility and the recovery of that cost through customer rates. Conceptually, a regulatory asset represents revenues that are expected to be recovered from customers in future periods. For example, in Order No. P.U. 13 (2009), the Board established a deferral account for Newfoundland Power's 2009 costs of customer energy conservation programming. The costs of this programming will be incurred in 2009; however, they will not be recovered from customers until after 2009. At year end 2009, the balance in this deferral account will be shown in Newfoundland Power's financial statements as a regulatory asset.

A regulatory liability typically arises as a result of a timing difference between recognition or receipt of an amount by a utility and the reflection of that amount in customer rates. Conceptually, a regulatory liability represents a reduction in revenue in future periods. For example, in Order No. P.U. 40 (2005), the Board approved Newfoundland Power's adoption of the accrual method of revenue recognition for regulatory purposes beginning in 2006. This approval had the effect of creating a liability of approximately $24.3 million in unbilled revenue as at year end 2005.[91] This liability was applied to reduce future revenue required by

[91] The $24.3 million was, in effect, an accounting accrual representing revenue associated with power deliveries up to December 31, 2005 which would not be billed to customers until January 2006.

Newfoundland Power over the five years ending 2010.[92] At year end 2005, the balance of unbilled revenue was shown in Newfoundland Power's financial statements as a regulatory liability.

The creation of regulatory assets and liabilities is an accepted feature of current Canadian regulatory practice. The recognition of regulatory assets and liabilities is currently permitted under Canadian GAAP.[93]

As of March 31, 2009, Newfoundland Power had regulatory assets of approximately $207 million and regulatory liabilities of approximately $85 million recorded in its financial statements.[94] Each of the regulatory assets and liabilities reflects a decision or decisions of the Board.[95] IFRS currently contains no guidance on the recognition of regulatory assets and liabilities.

---

92 As part of the Board's approval of Newfoundland Power's adoption of the accrual method of revenue recognition, consideration of disposition of this amount was required. The Board considered this matter in Order Nos. P.U. 40 (2005), P.U. 39 (2006), and P.U. 32 (2007).

93 Prior to 2009, Canadian GAAP contained guidance that effectively permitted the recognition of regulatory assets and liabilities. Effective 2009, the AcSB removed from Canadian GAAP the guidance that permitted recognition of regulatory assets and liabilities. For 2009 and 2010, Canadian regulated utilities effectively rely on U.S. GAAP (particularly, Statement of Financial Accounting Standards No. 71 *Accounting for the Effects of Certain Types of Regulation*) which permits recognition of regulatory assets and liabilities on a conceptually similar basis to that allowed under Canadian GAAP prior to 2009. Commencing in 2011, the recognition of regulatory assets and liabilities will be governed by IFRS.

94 Approximately 66% or $137 million, of Newfoundland Power's regulatory assets relate to future income taxes. Approximately 29% or $24 million of Newfoundland Power's regulatory liabilities relate to future income taxes. Commencing in 2009, Newfoundland Power is required by Canadian GAAP to recognize future income tax assets and liabilities arising from Board orders as regulatory assets and liabilities in its financial statements. Prior to this, future income tax assets and liabilities arising from Board orders were referred to in notes to the financial statements. There is no impact on customers from this change in presentation.

95 For a regulatory asset such as amortization true up deferral, the relationship to Board decision-making is explicit (see, for example, Order Nos. P.U. 39 (2006) and P.U. 32 (2007)). For a regulatory liability such as future removal and site restoration provision, the relationship to Board decision-making is less explicit. Board orders approving Newfoundland Power's depreciation rates effectively authorize the recovery of estimated future removal and restoration costs in depreciation rates applied during the useful life of the asset. This is consistent with the cost of service standard. However, financial presentation under Canadian GAAP requires that the future removal and site restoration costs be segregated from accumulated depreciation and shown as a liability. There is no impact on customers from this change in presentation.

IASB's Rate-regulated Project

Regulatory decision-making has, and is intended to have, economic impacts for regulated utilities. This has historically been reflected in the application of Canadian GAAP to regulated utilities. The absence of guidance on the recognition of regulatory assets and liabilities in IFRS has therefore created uncertainty for Canadian regulated utilities which are affected by the 2011 transition to IFRS.[96] This uncertainty has broader potential regulatory impacts.[97]

In December 2008, the IASB initiated a project on rate-regulated activities. In February and April 2009, the IASB considered the scope of the project.[98] The IASB currently expects to publish an exposure draft concerning the recognition and measurement criteria for regulatory assets and liabilities by July 2009.[99] A final standard is currently expected to be published by the IASB in June 2010.

---

96 This uncertainty is unlikely to be resolved prior to June 2010, however, some regulators are already considering transitional issues. In May 2009, the Alberta Utilities Commission developed Draft Rule 026 *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards* to clarify accounting procedures and reporting requirements resulting from the implementation of IFRS by Alberta utilities.

97 Changes in financial information contained in audited financial statements could have impacts on regulators' reliance upon that information. Changes in accounting treatment of regulatory assets and liabilities could impact regulatory decision-making which effectively creates them. The Canadian Association of Members of Public Utility Tribunals ("CAMPUT") has expressed these concerns to the International Financial Reporting Interpretations Committee of the IASB.

98 The IASB decided that the two criteria which should define rate-regulated activities are (i) an authorized body empowered to establish rates that bind customers, and (ii) the rate regulation is cost of service regulation. *IASB Meeting Staff Paper on Rate-regulated activities, April 2009.*

99 An *exposure draft* is a proposed accounting standard issued by a standards setting organization for the purposes of eliciting comment prior to finalizing the standard.

While currently it appears that the IASB accepts in principle that rate regulation may create assets and liabilities recognizable under IFRS, this does not constitute guidance in an accounting standards sense.[100] In the absence of a final standard indicating the details of recognition and measurement criteria, uncertainty will persist surrounding the treatment of regulatory assets and liabilities upon adoption of IFRS in 2011.

3.5.3 IFRS Transition at Newfoundland Power

Commencing in 2011, Newfoundland Power's financial statements must comply with IFRS, and must include comparative financial results for 2010.[101] This requires Newfoundland Power to assemble financial information during 2010 that complies with current Canadian GAAP and with IFRS.[102]

Newfoundland Power's plans for IFRS transition are focused upon being prepared to adopt IFRS in 2011. The transition to IFRS will be a material focus for the Company in 2009 and 2010.[103]

---

[100] As of February, 2009 the IASB "…generally agreed with the analysis supporting the staff's conclusion that cost-of-service regulation gives rise to items that meet the definition of an asset or a liability…" *IASB February, 2009 Meeting Summary and Observer Notes*. In its April 2009 meeting, the IASB "…generally agreed that the primary driver for recognition of assets and liabilities is the existence of future economic benefits or obligations." *IASB Update, April 2009*.

[101] Both current Canadian GAAP and IFRS require the presentation of comparative financial information for the current and previous reporting period.

[102] Newfoundland Power's current financial information systems can be configured to capture and report two sets of financial information for 2010. Accordingly, the additional costs associated with assembling two sets of financial information for 2010 are not currently expected to be material.

[103] Newfoundland Power assesses the IFRSs as part of a working group that includes all Canadian operating subsidiaries of Fortis Inc. that are affected by IFRS transition. The working group has retained the services of Deloitte LLP as independent consultants for IFRS issues. Ernst & Young LLP, the Company's external auditor, is also actively engaged in IFRS transition, which is overseen by the Audit and Risk Committee of Newfoundland Power's Board of Directors.

Newfoundland Power has reviewed all of the IFRSs.[104] For the IFRSs that have application to Newfoundland Power, the impacts have been assessed on a preliminary basis. Because the majority of IFRSs are expected to be modified between 2008 and 2011, the assessments are subject to change.[105]

Newfoundland Power has identified and assessed those IFRSs that have the greatest potential impact on the Company's current financial statements.[106] For example, IFRS differs from current Canadian GAAP regarding several aspects of measurement and recognition of property, plant and equipment, such as disposition or retirement of capital assets, general expenses capitalized ("GEC"), and capitalization policy regarding transformers, meters and standby equipment. The practical impact of differences between IFRS and current Canadian GAAP may be affected by the treatment of regulatory assets and liabilities under IFRS. For example, GEC may not be recognized as property, plant and equipment under IFRS, but may ultimately be appropriately recognized as a regulatory asset under IFRS. In such a circumstance, the differences between IFRS and current Canadian GAAP are effectively minimized.[107]

---

[104] Of the 37 IFRSs, approximately 15 do not appear to have any material application to Newfoundland Power's financial statements. Examples of these include *IFRS 6: Exploration for and evaluation of Mineral Resources; IFRS 8: Operating Segments; IAS 11: Construction Contracts;* and *IAS 21: The Effects of Changes in Foreign Exchange Rates.*

[105] See Footnote 86. A change to a current standard under IFRS before 2011 could change the impact of transition on Newfoundland Power. In addition, developments with respect to the IASB's Rate-regulated activities project could have the effect of altering the application of a current standard to Newfoundland Power.

[106] These standards are *IAS 12: Income Taxes; IAS 16: Property, Plant and Equipment; IAS 19: Employee Benefits; IAS 23: Borrowing Costs; IAS 36: Impairment of Assets; IAS 37: Provisions, Contingent Liabilities and Contingent Assets; IAS 38: Intangible Assets;* and *IFRS 1: First Time Adoption of IFRS.*

[107] In this circumstance, the difference would relate to presentation of GEC in financial statements. Current Canadian GAAP permits GEC to be included in property, plant and equipment. If IFRS were to permit recognition of GEC as a regulatory asset, then it would no longer be included in property, plant and equipment, but instead reflected as a regulatory asset. There would be no impact on customers from this change in presentation.

In Order No. P.U. 32 (2007), the Board ordered Newfoundland Power to file its next depreciation study relating to plant in service as of December 31, 2010. In light of Newfoundland Power's requirement to file IFRS compliant financial statements in 2011, which include comparative results for 2010 and 2011, it would be more appropriate that the next depreciation study relate to plant in service as of December 31, 2009. A depreciation study as of December 31, 2009 will provide detailed information concerning the Company's property, plant and equipment to be used in comparative financial statements for 2010 and 2011.[108]

In this Application, Newfoundland Power seeks the Board's approval that its next depreciation study relate to plant in service as of December 31, 2009.

3.6 REGULATORY DEFERRALS

This section of the evidence reviews the amortization of regulatory deferrals through 2013.

In this Application, Newfoundland Power is proposing amortization of 2009 conservation costs associated with customer programming under the 5-year Energy Conservation Plan over the remaining 4 years of the Plan, and amortization of third party costs related to this Application in 2010.

[108] The IFRS requirement to file comparative financial statements for 2010 and 2011 effectively makes December 31, 2009 the transition point for collection of financial information required for IFRS compliance. Newfoundland Power currently expects that IFRS will require more detailed financial statement disclosure relating to property, plant and equipment than required by current Canadian GAAP.

3.6.1 2009 Conservation Costs

2009 conservation costs associated with customer programming under the 5-year Energy Conservation Plan are forecast to be approximately $1.5 million.[109] 2009 is the first year of the 5-year Energy Conservation Plan.

In this Application, Newfoundland Power is proposing to recover the 2009 customer energy conservation programming costs, as charged to the Conservation Cost Deferral Account, over the remaining 4 years of the 5-year Energy Conservation Plan.

3.6.2 Application Costs

Newfoundland Power estimates that approximately $750,000 will be incurred by the Board and the Consumer Advocate as a result of this Application.

Newfoundland Power is proposing that these costs be recovered in 2010 customer rates.[110]

[109] Deferred recovery of these costs through the Conservation Cost Deferral Account was authorized by Order No. P.U. 13 (2009).

[110] In the past, the Board has ordered recovery of Application costs over a 3 year period (see Order Nos. P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), and P.U. 32 (2007)). In each of these cases it was expected that the rates determined in the Applications would be in effect for multiple years. It is not currently expected that the rates set as a result of this Application will be in effect beyond 2010.

1 **3.6.3 Summary of Regulatory Deferrals**

2 Table 3-18 summarizes current amortizations of regulatory deferrals approved by the Board
3 together with those proposed in this Application.

4

Table 3-18
Amortization of Regulatory Deferrals
***Pro forma* Revenue Requirement Impact**
2009 to 2013
($000s)

	2009	**2010**	**2011**	**2012**	**2013**
Revenue Deferrals					
2005 Unbilled Revenue[111]	(6,893)	(6,791)	-	-	-
Municipal Tax Liability[112]	(1,362)	(1,362)	-	-	-
Cost Recovery Deferrals					
Depreciation[111]	5,764	5,679	-	-	-
Replacement Energy[112]	598	598	-	-	-
Purchased Power Unit Cost Reserve[112]	(688)	(688)	-	-	-
Weather Normalization Reserve[112]	2,101	2,101	2,101	2,101	-
Conservation Cost Deferrals[113]	(1,516)	379	379	379	379
Application Costs[113]	-	750	-	-	-
Revenue Requirement Impacts	(1,996)	666	2,480	2,480	379

5

[111] Approved in Order No. P.U. 32 (2007). For revenue requirement purposes, the amortizations of the 2005 unbilled revenue and deferred costs related to depreciation include income tax effects.
[112] Approved in Order No. P.U. 32 (2007).
[113] As proposed in this Application.

SECTION 4: 2010 RATE BASE & REVENUE REQUIREMENTS

4.1 OVERVIEW

This section of the evidence addresses the Company's forecast 2010 average rate base and forecast 2010 revenue requirements.

4.2 FORECAST 2010 RATE BASE

Based on the Company's proposals in this application, forecast 2010 average rate base is approximately $**867** ***million.***

In Order No. P.U. 19 (2003), the Board ordered that the Asset Rate Base Method ("ARBM") should be used to calculate Newfoundland Power's rate base. In Order No. P.U. 32 (2007), the Board approved a test year rate base for Newfoundland Power that was calculated in accordance with the ARBM.

Newfoundland Power's forecast 2010 average rate base, as set out in this Application, including rate base allowances, is calculated in accordance with Board orders and regulatory practice.[1]

The Company's forecast 2010 average rate base is approximately $867 million.

Exhibit 6 shows the 2010 forecast average rate base.

[1] A report on 2010 Rate Base Allowances is found in *Volume 2: Supporting Materials, Tab* 2.

Changes to the Company's average rate base are principally the result of two factors: 1) plant investment, which includes annual capital expenditures[2] and 2) depreciation expense.[3]

The forecast 2010 average rate base includes the Company's forecast capital expenditures for 2009 which were approved in Order No. P.U. 27 (2008). The calculation of the Company's forecast 2010 average rate base also reflects the forecast 2010 capital expenditures of $64.7 million.

4.3 FORECAST 2010 REVENUE REQUIREMENTS

Based upon the Company's proposals in this Application, forecast 2010 revenue requirements are approximately $563.5 million.

The increase in revenue required in 2010 will result in an average increase in current customer rates of 6.1%.

---

[2] Each year, the Company's capital expenditures for the following year are considered and approved by the Board. Further detail on the capital forecast is provided in *Section 2.3.2 Capital Costs*.

[3] Annual depreciation expense is calculated using the composite depreciation rates approved by the Board in Order No. P.U. 32 (2007).

4.3.1 Summary of Revenue Requirements

The revenue requirements used to establish electrical rates are forecast to be $545.3 million in 2010.

Exhibit 7 shows the forecast 2010 revenue requirements.[4]

Table 4-1 shows a summary of the 2010 revenue requirements including the revenue required to be recovered from customer rates.

Table 4-1
Summary of 2010 Revenue Requirements
($000s)

Power Supply Cost	351,942
Operating Costs (including OPEBs)[5]	63,820
Depreciation & Related Amortization[6]	47,202
Income Taxes	21,167
Return on Rate Base	79,383
2010 Revenue Requirement	**563,514**
Deductions[7]	(18,202)
2010 Revenue Requirements from Rates	**545,312**

[4] Exhibit 7 compares the 2010 forecast in the absence of the proposals contained in this Application to the revenue requirements proposed in this Application.
[5] For revenue requirement purposes, operating costs is the total of Exhibit 7, lines 5, 6 and 7, Proposed.
[6] For revenue requirement purposes, depreciation and related amortization is the total of Exhibit 7, lines 8 and 9, Proposed.
[7] See Exhibit 7, line 19.

4.3.2 Costs and Depreciation

Table 4-2 shows forecast 2010 power supply cost.

Table 4-2
2010 Power Supply Cost
($000s)

Purchases from Hydro	353,726
Amortizations	
Weather Normalization Reserve	2,101 [8]
Replacement Energy Cost	598 [9]
Unit Cost Reserve	(688) [10]
Elasticity Impact	(3,795) [11]
Proposed	**351,942**

Table 4-3 shows forecast 2010 operating costs.[12]

Table 4-3
2010 Operating Costs (including OPEBs)
($000s)

Existing[13]	56,761
Amortization of CDM Costs	379 [14]
Increased OPEB Costs	5,930 [15]
Hearing Costs	750 [16]
Proposed	**63,820**

[8] In Order No. P.U. 32 (2007), the Board approved a 5-year amortization of a $6.8 million balance (net of tax) in the degree day component of the Weather Normalization Reserve. This amortization will conclude in 2012.

[9] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of $1.1 million (net of tax) of 2007 replacement energy costs. This amortization will conclude in 2010.

[10] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of a $1.3 million balance (net of tax) in the Purchased Power Unit Cost Variance Reserve. This amortization will conclude in 2010.

[11] Newfoundland Power's methodology for forecasting elasticity effects is consistent with that used for the customer and energy forecast accepted by the Board in Order No. P.U. 32 (2007).

[12] Exhibits 1 and 2 show the forecast operating costs for 2010. These are reviewed in detail in *Section 2.3.1 Operating Costs*.

[13] For revenue requirement purposes, existing operating costs is the total of Exhibit 7, lines 5, 6 and 7, Existing.

[14] The Company's proposal regarding the amortization of CDM costs is reviewed in *Section 3.6.1 2009 Conservation Costs*.

[15] The Company's proposal regarding OPEBs are reviewed in *Section 3.4.3 Other Post Employment Benefits*. See footnote 2 to Exhibit 7.

[16] The Company's proposal regarding the amortization of the Application costs is reviewed in *Section 3.6.2 Application Costs*.

Table 4-4 shows forecast 2010 depreciation and related amortizations.

Table 4-4
2010 Depreciation Cost and Related Amortization
($000s)

Depreciation	43,341
Amortization of Cost Recovery Deferral	3,861 [17]
Depreciation and Related Amortization	**47,202**

Table 4-5 shows forecast 2010 income taxes.

Table 4-5
2010 Income Taxes
($000s)

Existing	13,132
Tax Effects of Application Proposals	8,035 [18]
Proposed	**21,167**

[17] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of deferred 2006 and 2007 depreciation costs. This amortization will conclude in 2010.

[18] The tax effects of the Application proposals are as follows:

	($000s)
Increase in Forecast Revenue from Rates, Exhibit 7, line 27	33,687
Transfers to the RSA Included in Existing Rates, Exhibit 7, line 21	(6,128)
Increase in Taxable Revenue	27,559
Reduction in Tax Deductible Expenses (purchased power, operating, interest)	2,688
Increase in Taxable Income	30,247
Tax Rate	32.0%
Increase in Cash Income Taxes	9,679
Decrease in Future Income Taxes	(1,644)
Increase in Total Income Taxes	**8,035**

4.3.3 Return on Rate Base

Exhibit 8 presents proposed 2010 return on rate base.

Table 4-6 summarizes the proposed 2010 return on rate base and rate of return on rate base.

Table 4-6
2010 Return on Rate Base
($000s)

Forecast Average Rate Base	867,396[19]
Forecast Regulated Returns	
Debt	35,936
Preferred Equity	573
Common Equity	42,874
Return on Rate Base	**79,383**
Rate of Return on Rate Base (%)	**9.15**[20]

4.3.4 Deductions and Revenue Amortizations

Table 4-7 shows forecast 2010 deductions from revenue requirements.

Table 4-7
2010 Deductions
($000s)

Other Revenue	(13,672)[21]
2005 Unbilled Revenue	(4,618)[22]
Other Adjustments	88
Proposed	**(18,202)**

[19] Forecast average rate base is shown in Exhibit 6, line 27.

[20] The rate of return on rate base is calculated as ($79,383,000 divided by $867,396,000) equals 9.15%, as shown in Exhibit 8. The range of return on rate base proposed in this Application is 8.97% to 9.33% based upon a 36 basis point range. A 36 basis point range of return on rate base was approved by the Board in Order Nos. P.U. 36 (1998-99), P.U. 19 (2003) and P.U. 32 (2007).

[21] Composed of $13,800,000 (existing other revenue) minus $128,000 (interest on rate stabilization account).

[22] The amortization of 2005 Unbilled Revenue reflects the Board's approval in Order No. P.U. 32 (2007) of a 3-year amortization of $13.9 million in revenue. This amortization will conclude in 2010.

4.3.5 Required Revenue Increase

Table 4-8 shows the forecast increase in revenue from rates of $33.9 million required to meet the Company's proposed 2010 revenue requirement.

Table 4-8
2010 Required Revenue Increase
($000s)

2010 Proposed Revenue From Rates	**545,312**
Revenue From Existing Rates	(514,817)
Elasticity Impacts	3,424 [23]
Required Increase in Revenue from Rates	**33,919**

The increase in revenue from rates for 2010 requires an average increase in current customer rates of 6.1%, effective January 1, 2010.

Exhibit 10 shows the 2010 average rate change.

[23] See Exhibit 10, line 1.

SECTION 5: CUSTOMER RATES

5.1 OVERVIEW

Based upon the proposals in this Application, Newfoundland Power forecasts that in 2010 the number of customers it serves will increase by 1.1%, energy sales will increase by 1.0% and peak demand will increase by 1.0%.

An average increase in customer rates of 6.1% is required to provide the proposed 2010 test year revenue requirement. The Company is proposing that customers served under the Domestic rate receive an increase 0.7% higher than average and that customers served under General Service rates 2.1, 2.2 and 2.3 receive an increase 1% to 2% lower than average.

This Application proposes no changes to the existing mechanisms that provide Newfoundland Power a reasonable opportunity to recover its supply costs in customer rates.

5.2 CUSTOMER, ENERGY AND DEMAND FORECAST

The forecast of customers and their load requirements is a primary input to determine customer rates.

This section of evidence reviews Newfoundland Power's 2010 customer, energy and demand forecast.

5.2.1 The Customers Served

Newfoundland Power is the largest distributor of electricity on the Island interconnected grid and is responsible for retail pricing for its approximately 240,000 customers.[1]

Table 5-1 provides the percent of customers and sales by class.

Table 5-1
Customers Served
2010 Forecast

Rate	Class of Service	% of Total Customers	% of Total Energy Sales
1.1	Domestic	86.6	60.4
2.1	General Service 0-10 kW	5.0	1.7
2.2	General Service 10-100 kW (110 kVA)	3.7	12.2
2.3	General Service 110-1000 kVA	0.5	16.8
2.4	General Service 1000 kVA and Over	-[2]	8.2
4.1	Street and Area Lighting Service	4.2	0.7
Total		**100.0**	**100.0**

The customers served by Newfoundland Power are predominantly Domestic customers. Approximately 60% of Newfoundland Power's annual energy sales are to Domestic customers.

[1] Hydro serves approximately 23,000 rural customers on the Island interconnected grid. Hydro's rural customers on the Island interconnected grid pay rates that are the same as those of Newfoundland Power's customers. The Company's rate design practices, therefore, affect all retail electricity customers on the Island interconnected grid.

[2] The 67 customers in Rate 2.4 comprise less than 0.03% of Newfoundland Power's total customers.

5.2.2 The Forecast

The Company's customer, energy and demand forecast reflects the impact of the rate proposals in this Application.[3] The forecast number of customers and their load requirements is a primary input used to determine revenue from customer rates.

Table 5-2 shows the Company's forecast number of customers for 2009 and 2010.

Table 5-2
Forecast Number of Customers
2009 to 2010

	2009F	**2010F**
Domestic	206,767	209,074
General Service		
0-10 kW	12,174	12,115
10-100 kW (110 kVA)	8,809	8,991
110-1000 kVA	1,077	1,088
1000 kVA and Over	69	67
Total General Service	22,129	22,261
Street and Area Lighting	10,005	10,096
Total	**238,901**	**241,431**

The number of customers served by Newfoundland Power is forecast to increase by approximately 1.1% from 2009 to 2010.

[3] See Appendices B and C to the *Customer, Energy and Demand Forecast* found in *Volume 2: Supporting Materials, Tab 6*.

Table 5-3 shows the Company's forecast energy sales for 2009 and 2010.

Table 5-3
Forecast Energy Sales
2009 to 2010
(GWh)

	2009F	**2010F**
Domestic	3,204.6	3,234.7
General Service		
0-10 kW	89.7	89.6
10-100 kW (110 kVA)	647.4	655.5
110-1000 kVA	889.5	901.8
1000 kVA and Over	435.7	437.3
Total General Service	2,062.3	2,084.2
Street and Area Lighting	36.4	36.0
Total	**5,303.3**	**5,354.9**

Newfoundland Power's energy sales are forecast to increase by approximately 1.0% from 2009 to 2010.[4]

[4] This reflects 2010 elasticity effects of 40.7 GWh directly resulting from the proposed 2010 customer rate increase. It also reflects a sales reduction of 0.4 GWh in 2009 and 3.3 GWh in 2010 as a result of customer energy conservation programming.

Table 5-4 shows the Company's forecast energy and peak demand supply requirements for 2009 and 2010.

Table 5-4
Forecast Supply Requirements[5]
2009 to 2010

	2009F	**2010F**
Energy (GWh)		
Produced[6]	425.9	428.8
Purchased	5,192.6	5,244.2
Total	5,618.5	5,673.0
Peak Demand (MW)		
Produced[7]	117.93	117.93
Purchased	1,144.76 [8]	1,157.12
Total	1,262.69 [9]	1,275.05

Newfoundland Power's energy purchases from Hydro are forecast to increase by 1.0% from 2009 to 2010. Purchased peak demand is forecast to increase by approximately 1.1% from 2009 to 2010.

Newfoundland Power's Customer, Energy and Demand Forecast is found in *Volume 2: Supporting Materials, Tab 6.*

---

[5] The forecast supply requirement for 2010 assumes approval of the rate increase proposed in this Application.
[6] The produced energy reflects the normalized production of Newfoundland Power's hydro generating facilities.
[7] Produced demand is the generation credit provided for in Hydro's wholesale rate structure.
[8] The purchased demand for 2009 reflects the forecast purchased demand from Hydro for the winter period of December 2009 to March 2010. This amount is Newfoundland Power's forecast billing demand from Hydro for 2010.
[9] The total represents the maximum demand forecast to be served by Newfoundland Power for the winter period of December 2009 to March 2010.

5.3 RATE CHANGE PLAN

An average increase in customer rates of 6.1% is required to provide the proposed 2010 revenue requirement.

This section of the evidence reviews the current status of Newfoundland Power's comprehensive assessment of retail rate designs which is ongoing. It also reviews the 2010 customer rate proposals in this Application.

For 2010, the Company is proposing to (i) recover the required increase in revenue from rates through increases in energy charges and (ii) vary the rate increase by customer rate class to continue progress towards target revenue to cost ratios of 90% to 110% for each rate class.

5.3.1 The Retail Rate Review

Newfoundland Power's Domestic and General Service Rates are currently being assessed as part of a comprehensive retail rate review (the "Retail Rate Review").[10] The objectives of the Retail Rate Review include: (i) to facilitate the exchange of information necessary to conduct a review of customer rate designs; (ii) to provide a mechanism for the participation of other interested parties in the process; and (iii) where appropriate, to recommend new rate designs for implementation. The new rate designs will focus on providing a price signal to customers that better reflects marginal costs.

---

[10] The Retail Rate Review was provided for as part of the settlement agreement reached in respect of Newfoundland Power's 2008 General Rate Application (the "Settlement Agreement"). In Order No. P.U. 32 (2007), the Board observed that the proposed scope, objectives and processes will provide an open and transparent process to evaluate the designs of Newfoundland Power's rates (see p. 52).

The Retail Rate Review has proceeded substantially in accordance with its original plan.[11]

A report on customer feedback obtained on alternative rate designs is expected to be filed with the Board in June 2009. It is expected that this information, together with that generated to date in the processes associated with the Retail Rate Review, will be inputs for assessing rate design alternatives in a Technical Conference later in 2009. It is anticipated that the Retail Rate Review process will be ongoing concurrent with this Application.

The Retail Rate Review includes consideration of a number of changes in the customer charges that apply in each class. These include new customer charges that better reflect differing customer cost attributes within a class and reduction in customer charges for the larger General Service customers to better reflect current metering practices.

Given the potential for changes to customer charges that may result from the Retail Rate Review, the Company is proposing to maintain its current customer charge levels in this Application. The current relationship of demand and energy charges to marginal costs indicates that an emphasis on increasing energy charges is reasonable at this time.[12] Accordingly, the required increase in revenue from rates resulting from this Application for the Domestic and General Service classes, is proposed to be recovered through increases in energy charges. This approach is broadly consistent with the marginal cost focus of the Retail Rate Review.

---

[11] The Settlement Agreement indicated a proposed timeline for the Retail Rate Review. A scope document outlining the purpose, scope and analysis criteria for a comprehensive Rate Design Report was filed with the Board on February 12th, 2008. A Rate Design Report study plan was filed with the Board on May 14th, 2008. The Rate Design Report was filed with the Board on January 28th, 2009. During the period March to April 2009, an independent market research firm conducted focus group sessions to gather information on Domestic customer views on alternative rate designs.

[12] See Rate Design Report, Section 4.1.3 *Demand Charges,* p.64.

5.3.2 Revenue to Cost Ratios

Newfoundland Power assesses the fairness of its rates by comparing the revenue collected from each class with the cost to serve each class, as determined through an embedded cost of service study (i.e., the "revenue to cost ratio").

The Company has updated the embedded cost of service study to reflect 2008 results (the "Cost of Service Study"). The Cost of Service Study is provided in *Volume 2: Supporting Materials, Tab 7*.

Table 5-5 shows the current revenue to cost ratios from the Cost of Service Study for each rate class.[13]

Table 5-5
Cost of Service Study Results

Class of Service	Rate Code	Revenue to Cost Ratios %
Domestic	1.1	94.3
General Service 0-10 kW	2.1	115.8
General Service 10-100 kW (110 kVA)	2.2	114.9
General Service 110-1000 kVA	2.3	110.3
General Service 1000 kVA and Over	2.4	104.4
Street and Area Lighting	4.1	103.2

[13] The cost recovery results by class from the Cost of Service Study are not materially different than the cost recovery by class used in the rate evaluation presented in the Rate Design Report. The cost recovery by class used in the Rate Design Report was based on the results of the 2006 embedded cost of service study incorporating the 2007 wholesale purchased power rate, the results of the most recent depreciation study and the reflection of revenues based on customer rates in effect July 1st, 2008.

Maintaining revenue to cost ratios for each class within the range of 90% to 110% has been an accepted approach to ensure that there is no undue cross-subsidization among the various classes.[14]

The revenue to cost ratios for the General Service 0-10 kW class (Rate 2.1) and 10-100 kW (110 kVA) class (Rate 2.2) are materially greater than 110%, while the General Service 110-1000 kVA class (Rate 2.3) is slightly above 110%. Rates should change to reduce the revenue to cost ratios for these classes.[15]

In 2007, Newfoundland Power indicated it intended to bring all customer classes within the target revenue to cost ratio range at its next general rate proceeding.[16] The customer rates proposed in this Application achieve continued progress towards the target 90% to 110% cost recovery range in 2010. However, the customer rates proposed in this Application do not achieve the target revenue to cost ratios for Rates 2.1 and 2.2. The Company is now proposing to complete the cost recovery adjustments to achieve the target revenue to cost ratios for Rates 2.1 and 2.2 coincident with implementation of the rates that result from the Retail Rate Review.[17]

---

[14] This is consistent with the views of the Board as expressed in Order No. P.U. 7 (1996-97), where the Board stated: "The Board agrees with the philosophy that it is not necessary to achieve a 100% revenue to cost ratio for all classes and takes no exception to a variance of up to 10%, …".

[15] To provide for recovery of total revenue requirement effectively requires that another class, or classes, receive an above average rate increase. Since the Domestic class is the only class with a revenue to cost ratio less than 100%, it is practically required that the Domestic class receive an above average increase if the over-recovery in classes General Service 0-10 kW, 10-100 kW and 110-1000 kVA classes is to be addressed.

[16] In Order No. P.U. 32 (2007), the Board accepted that this approach was reasonable (See p.28).

[17] The Rate Design Report considers a rate design change for Rate 2.1 and Rate 2.2 to eliminate the material change in average price for customers that move between these classes. (See Rate Design Report, Section 4.1.6 *Blocking Structures*, at p.70 through 75). Implementing this rate design change will result in increases in cost for a material number of customers. By achieving the target revenue to cost ratios coincident with implementation of the rate design change described in the Rate Design Report, as proposed in this Application, the Company will effectively reduce the rate increases that would be experienced by this group of affected customers.

Table 5-6 provides the 2010 proposed relative rate change by class and the resulting *pro forma* revenue to cost ratios.

Table 5-6
Proposed Relative Rate Changes by Class

Rate	Class	Relative to Average	*Pro forma* Revenue to Cost Ratios
1.1	Domestic	0.7% above[18]	94.8
2.1	General Service 0-10 kW	2% below	113.6
2.2	General Service 10-100 kW (110 kVA)	2% below	112.8
2.3	General Service 110-1000 kVA	1% below	109.3
2.4	General Service 1000 kVA and Over	Equal	104.4
4.1	Street and Area Lighting	Equal	103.1

The proposed changes in customer rates will result in reduced revenue to cost ratios for Rates 2.1, 2.2 and 2.3 and an increased revenue to cost ratio for Rate 1.1.

5.3.3 The Proposed Rates

An average increase in customer rates of 6.1% is required to provide the proposed 2010 revenue requirement.

Exhibit 10 provides the computation of the proposed 6.1% average increase in customer rates.

The proposed rates for all classes of service, excluding Street and Area Lighting, were derived by recovering the required increase in revenue from rates through increased energy charges.

[18] The Domestic class increase relative to average will vary slightly from 0.7% 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.

The energy component of the Maximum Monthly Charge applicable to General Service Rates 2.2, 2.3, and 2.4 is proposed to increase by the overall average increase in customer rates.

The Street and Area Lighting rates were derived, consistent with past practice, so that the prices of fixtures, poles and wiring vary in a manner reflective of the differences in fixed costs and variable operating costs.

It is proposed that the availability of the Curtailable Service Option for General Service customers be maintained based on the current credit of $29 per kVA.

Exhibit 12 provides a comparison of existing and proposed customer rates.[19]

5.4 SUPPLY COST RECOVERY MECHANISMS

Newfoundland Power currently has regulatory mechanisms which permit reasonable recovery of wholesale demand and energy supply costs in customer rates.

This section of the evidence reviews the operation of these supply cost recovery mechanisms which have yielded benefits to customers totaling approximately $3.6 million between 2005 and 2008.

No changes to these mechanisms are proposed in this Application.

[19] The existing and proposed rates reflect the Rate Stabilization and Municipal Adjustment Factors effective July 1, 2008.

5.4.1 Demand Management Incentive Account

Hydro's demand and energy wholesale supply rate provides an incentive to Newfoundland Power to take reasonable actions to minimize the peak demand requirements of its customers.[20] Hydro and Newfoundland Power have agreed on a weather normalization mechanism for use in the application of the demand and energy wholesale energy supply rate. While this weather normalization mechanism generally provides reasonable estimates of adjustments related to weather, it does not (and cannot) eliminate volatility associated with changes in Newfoundland Power's customers' peak demand.[21]

In Order No. P.U. 44 (2004), the Board approved the establishment of a reserve as part of its approval of the demand and energy wholesale rate.[22] The effect of the reserve is to limit the impact on the Company of variability in demand supply costs to 1% of test year demand supply costs.[23] In Order No. P.U. 32 (2007), the Board approved the establishment of the Demand Management Incentive Account (the "DMI Account") to replace the reserve established by Order No. P.U. 44 (2004).

---

[20] The peak is the maximum amount of customer energy usage required during any 15-minute time period during the year (including Company usage and energy losses).

[21] The 95% statistical confidence of the weather normalization mechanism is approximately ± 20%. (see: Hydro's *Newfoundland Power Demand and Energy Rate Implementation*, July 2004, p.10). With this level of confidence, material demand volatility remains. In the 2004-2005 winter season, peak occurred on December 6, 2004. Weather conditions on that day were unusual. Calculations under the weather normalization mechanism indicated that peak demand should be increased by approximately 40 MW to reflect normal peak day conditions. Following a review of the matter, Hydro and Newfoundland Power agreed that a peak demand adjustment of 14 MW was a more appropriate reflection of the weather's impact upon the December 6, 2004 peak. The 26 MW difference in normalization adjustments would have translated into approximately $1.45 million in additional supply costs for Newfoundland Power in 2005 (26,000 kW times $4.65 per kW demand charge times 12 months).

[22] In Order No P.U. 35 (2005), the Board approved the definition of the Purchased Power Unit Cost Variance Reserve Account (the "PPUCVR Account") for inclusion in the Company's System of Accounts. The PPUCVR Account defined the mechanics of the reserve mechanism contemplated by Order No. P.U. 44 (2004).

[23] A 1% variance in billing demand currently causes a variance in purchased power costs from that reflected in customer rates by approximately $529,000 based on the current wholesale demand charge of $4 per kW per month.

From 2005 through 2008, there has been approximately $3.2 million of demand related wholesale supply cost reductions credited to customers' benefit as a result of the operation of the DMI Account and its predecessor reserve.[24] This reflects the aggregate reduced peak demand of Newfoundland Power's customers.

A report on the performance of the Demand Management Incentive Account is provided in *Volume 2, Supporting Documents, Tab 8.* [25]

No changes are proposed for the DMI Account in this Application.

5.4.2 Energy Supply Cost Recovery

Load requirements on the system increase annually, principally as a result of the addition of new customers. Changes in Hydro's wholesale rate in 2007 resulted in a dramatic increase in the cost to Newfoundland Power to supply increases in customer load (the "Marginal Supply Cost").[26] The increased Marginal Supply Cost is the result of higher fuel costs related to production at Holyrood.[27] Marginal Supply Costs currently exceed the average supply costs which are embedded in Newfoundland Power's Customer Rates.[28]

---

[24] In 2006, approximately $2.1 million in supply cost reduction associated with reduced demand costs were credited to the reserve. This amount was credited to be amortized to customers' benefit over 3 years by Order No. P.U. 32 (2007), p.60. Approximately $500,000 in supply cost reductions credited to the reserve in 2007 were amortized to customers benefit through the RSA by Order No. P.U. 6 (2008). Approximately $600,000 in supply cost reductions were credited to the DMI Account in 2008 and will be amortized to customers' benefit through the RSA in accordance with Order No. P.U. 21 (2009).

[25] This report is filed in accordance with Order No. P.U. 32 (2007) (See p.61).

[26] In January 2007, the 2nd block of the wholesale energy rate from Newfoundland Hydro increased from 4.7¢ per kWh to 8.805¢ per kWh. The wholesale rate effective January 1st, 2007 remains the wholesale rate for forecasting supply costs for 2010.

[27] The fuel cost at Holyrood is reflected in Hydro's wholesale supply rate 2nd block energy charge.

[28] This difference relates to energy supply costs as shown in Table 5-7.

In Order No. P.U. 32 (2007), the Board approved the inclusion of a clause in the Rate Stabilization Account (the "RSA") to ensure reasonable recovery of prudently incurred energy supply costs. The amount charged to the RSA is the difference between the marginal energy supply cost and the average energy supply cost (the "Energy Supply Cost Variance").

A report on the current practice of recovery of the Energy Supply Cost Variance through the RSA is provided in *Volume 2, Supporting Documents, Tab 9.*[29]

Table 5-7 provides the computation of the current Energy Supply Cost Variance on a ¢ per kWh basis.

Table 5-7
Energy Supply Cost Variance
¢ per kWh

Difference in energy costs		
Average Test Year Energy Supply Cost[30]	5.535	¢/kWh (A)
Wholesale rate 2nd Block price	8.805	¢/kWh (B)
Energy Supply Cost Variance	3.270	¢/kWh (C = B – A)

For 2008, the transfer to the RSA resulting from the Energy Supply Cost Variance provided a benefit to customers of approximately $400,000. This occurred because Newfoundland Power's energy purchases from Hydro in 2008 were lower than the 2008 test year forecast.

29 In Order No. P.U. 32 (2007), the Board indicated they would carry out a review of the recovery of the Energy Supply Cost Variance through the RSA at the next general rate proceeding.

30 The average cost of energy was determined by applying the current wholesale demand and energy supply rate to the forecast 2009 energy purchases.

For 2009, there is forecast to be a $3.0 million Energy Supply Cost Variance transfer to be recovered through the RSA.[31] The Energy Supply Cost Variance results from the addition of new customers. It can be expected to continue for so long as load growth continues and the Marginal Supply Cost remains higher than the average supply cost included in customer rates.

There continues to be a requirement for the provision for the recovery of the Energy Supply Cost Variance through the RSA to permit Newfoundland Power the opportunity to recover prudently incurred energy supply costs.

In this Application, no changes are proposed for the Energy Supply Cost Variance clause in the RSA.

[31] As a result of this Application, forecast 2010 wholesale supply costs will be rebalanced with customer rates. Accordingly, no Energy Supply Cost Variance is forecast for year-end 2010. In the absence of this Application, a forecast Energy Supply Cost Variance of $6.1 million would be recovered in the July 1, 2011 RSA adjustment.

Newfoundland Power Inc.

Operating Costs by Function
2007 to 2010F
($000s)

	Function	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010
1	Distribution	6,575	6,683	7,068	7,365
2	Transmission	587	585	569	585
3	Substations	2,311	2,123	2,319	2,432
4	Power Produced	2,480	2,586	2,652	2,723
5	Administrative & Engineering Support	5,585	5,604	5,734	5,879
6	Telecommunications	1,399	1,394	1,387	1,380
7	Environment	581	398	398	409
8	Fleet Operations & Maintenance	1,497	1,572	1,392	1,492
9					
10	**Electricity Supply**	**21,015**	**20,945**	**21,519**	**22,265**
11					
12	Customer Services	9,180	9,571	8,921	9,077
13	Conservation	-	-	2,451	2,977
14	Uncollectible Bills	1,093	834	963	963
15					
16	**Customer Services**	**10,273**	**10,405**	**12,335**	**13,017**
17					
18	Information Systems	2,752	2,487	2,736	2,817
19	Financial Services	1,646	1,502	1,571	1,658
20	Corporate & Employee Services	10,777	10,463	11,729	11,901
21	Insurances	1,641	1,344	1,100	1,100
22					
23	**General**	**16,816**	**15,796**	**17,136**	**17,476**
24					
25	**Sub-Total**	**48,104**	**47,146**	**50,990**	**52,758**
26					
27	Deferred CDM costs	-	-	(1,516)	379
28	Deferred Regulatory Costs	-	199	199	951
29	Pension Costs	5,701	3,040	2,577	5,701
30					
31	**Total Gross Operating Cost**	**53,805**	**50,385**	**52,250**	**59,789**
32					
33	Transfer to GEC	(1,966)	(1,797)	(1,900)	(1,900)
34		**51,839**	**48,588**	**50,350**	**57,889**

Newfoundland Power Inc.

Operating Costs by Breakdown
2007 to 2010F
($000s)

	Breakdown	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010
1	Regular and standby	$ 24,371	$ 24,485	$ 26,105	$ 27,486
2	Temporary	2,303	2,335	1,860	1,623
3	Overtime	1,588	1,634	1,636	1,640
4	**Total Labour**	**28,262**	**28,454**	**29,601**	**30,749**
5					
6	Vehicle Expenses	1,495	1,569	1,392	1,492
7	Operating Materials	1,060	957	1,063	1,082
8	Inter-Company Charges	103	37	40	40
9	Plants, Subs, System Oper & Bldgs	1,915	1,782	1,930	1,952
10	Travel	1,081	1,290	1,139	1,160
11	Tools and Clothing Allowance	876	1,168	1,088	1,108
12	Miscellaneous	1,179	1,039	1,082	1,146
13	Conservation	-	-	295	581
14	Taxes and Assessments	663	(10)	750	750
15	Uncollectible Bills	1,093	834	963	963
16	Insurance	1,641	1,344	1,100	1,100
17	Retirement Allowance	212	308	285	325
18	Education, Training, Employee Fees	193	265	265	270
19	Trustee and Directors' Fees	380	411	408	394
20	Other Company Fees	1,544	1,469	2,000	1,904
21	Stationery & Copying	320	204	332	337
22	Equipment Rental/Maintenance	671	708	708	721
23	Telecommunications	1,562	1,622	1,532	1,521
24	Postage	1,371	1,312	1,372	1,397
25	Advertising	391	531	1,379	1,431
26	Vegetation Management	1,340	1,377	1,495	1,550
27	Computing Equipment & Software	752	475	771	785
28	**Total Other**	**19,842**	**18,692**	**21,389**	**22,009**
29					
30	**Sub-Total**	**48,104**	**47,146**	**50,990**	**52,758**
31					
32	Deferred CDM costs	-	-	(1,516)	379
33	Deferred Regulatory Costs	-	199	199	951
34	Pension Costs	5,701	3,040	2,577	5,701
35					
36	**Total Gross Operating Cost**	**53,805**	**50,385**	**52,250**	**59,789**
37					
38	Transfer to GEC	(1,966)	(1,797)	(1,900)	(1,900)
39		**51,839**	**48,588**	**50,350**	**57,889**

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Statements of Income
($000s)

		Actual		Forecast	
		2007	**2008**	**2009**	**2010E**
1	Revenue From Rates	474,054	497,360	506,284	511,625
2	Amortization of 2005 Unbilled Revenue	2,714	7,210	4,618	4,618
3	Transfers from (to) the RSA	3,044	(948)	3,031	6,128
4		479,812	503,622	513,933	522,371
5					
6	Purchased Power Expense	326,359	334,006	344,155	353,726
7	Deferred Replacement Energy Costs	(1,795)	598	598	598
8	Amortization of Weather Normalization Reserve	1,732	2,101	2,101	2,101
9	Demand Management Incentive Account Adjustments	-	641	-	-
10	Amortization of Purchased Power Unit Cost Variance Reserve	482	(688)	(688)	(688)
11		326,778	336,658	346,166	355,737
12					
13	Contribution	153,034	166,964	167,767	166,634
14					
15	Other Revenue	10,420	13,267	14,004	13,800
16					
17	Other Expenses:				
18	Operating Expenses[1]	47,501	47,132	50,844	52,774
19	Pension Costs	5,701	3,040	2,577	5,701
20	Deferred Costs	(5,793)	-	(1,516)	-
21	Amortization of Deferred Cost Recoveries	-	3,862	3,863	3,861
22	Depreciation	39,955	40,649	41,852	43,338
23	Finance Charges	33,462	33,507	34,917	36,211
24		120,826	128,190	132,537	141,885
25					
26	Income Before Income Taxes	42,628	52,041	49,234	38,549
27	Income Taxes	12,176	19,146	16,170	12,584
28					
29	Net Income	30,452	32,895	33,064	25,965
30	Preferred Dividends	586	554	579	573
31					
32	Earnings Applicable to Common Shares	29,866	32,341	32,485	25,392
33					
34	**Rate of Return and Credit Metrics**				
35	Rate of Return on Rate Base (percentage)	8.07%	8.20%	8.15%	7.27%
36	Regulated Return on Book Equity (percentage)	8.66%	9.13%	8.88%	6.87%
37	Return on Book Equity (percentage)	8.62%	8.86%	8.61%	6.57%
38	Interest Coverage (times)	2.2	2.5	2.4	2.0
39	CFO Pre-W/C + Interest / Interest (times)	2.6	3.1	3.1	2.8
40	CFO Pre-W/C / Debt (percentage)	12.6%	15.8%	15.9%	13.0%

[1] Operating expenses shown are before adjustment for non-regulated expenses.

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Statements of Retained Earnings
($000s)

		Actual		Forecast	
		2007	**2008**	**2009**	**2010E**
1	Balance - Beginning	265,566	286,350	303,417	310,721
2	Net Income for the Period	30,452	32,895	33,064	25,965
3		296,018	319,245	336,481	336,686
4					
5	Dividends				
6	Preference Shares	586	554	579	573
7	Common Shares	9,082	15,274	25,181	14,861
8		9,668	15,828	25,760	15,434
9	Balance - End of Period	286,350	303,417	310,721	321,252

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Balance Sheets
($000s)

		Actual		Forecast	
		2007	**2008**	**2009**	**2010E**
1	**Assets**				
2	**Current assets**				
3	Cash	$ 1,067	$ 629	$ -	$ -
4	Accounts Receivable	70,792	63,508	68,472	71,022
5	Materials and Supplies	5,248	5,391	5,500	5,586
6	Prepaid Expenses	1,190	1,292	1,314	1,336
7	Regulatory Assets	7,086	9,426	10,811	6,077
8	Income Tax Receivable	1,780	-	-	-
9		87,163	80,246	86,097	84,021
10					
11	**Capital assets**	746,474	770,581	798,438	826,340
12	**Deferred charges**	88,674	93,273	99,357	101,022
13	**Regulatory assets**	61,808	55,988	188,880	197,558
14	**Customer Finance Plans**	1,811	1,776	1,750	1,750
15		$ 985,930	$ 1,001,864	$ 1,174,522	$ 1,210,691
16					
17					
18	**Liabilities and Shareholders' Equity**				
19	**Current Liabilities**				
20	Short-term borrowings	$ -	$ 10	$ -	$ -
21	Accounts payable and accrued charges	68,685	65,547	63,101	63,909
22	Regulatory Liabilities	9,332	6,428	9,569	-
23	Current Installments of long-term debt	4,550	4,550	5,200	5,200
24	Future Income Taxes			134	974
25	Income Tax Payable	-	7,633	-	-
26		82,567	84,168	78,004	70,083
27					
28	**Regulatory liabilites**	60,281	54,817	73,316	80,778
29	**Other liabilities**	38,082	45,001	50,195	56,113
30	**Long-term debt**	438,977	433,604	464,545	484,301
31					
32	**Future Income Taxes**	-	1,184	118,247	118,670
33					
34	**Shareholders' Equity**				
35	**Common shares**	70,321	70,321	70,321	70,321
36	**Preference shares**	9,352	9,352	9,173	9,173
37	**Retained earnings**	286,350	303,417	310,721	321,252
38		366,023	383,090	390,215	400,746
39		$ 985,930	$ 1,001,864	$ 1,174,522	$ 1,210,691

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Statements of Cash Flows
($000s)

		Actual		Forecast	
		2007	2008	2009	2010E
1	**Cash From (Used In) Operating Activities**				
2	Net Earnings	$ 30,452	$ 32,895	$ 33,064	$ 25,965
3					
4	**Items not affecting cash:**				
5	Amortization of capital assets	39,955	40,649	41,852	43,338
6	Amortization of deferred charges	318	298	271	225
7	Change in regulatory assets and liabilities	(6,180)	305	1,423	(4,715)
8	Future income taxes	-	1,184	1,866	357
9	Accrued employee future benefits	(7,407)	(4,471)	(4,417)	(1,459)
10	Change in non-cash working capital	(7,887)	14,191	(15,174)	(1,652)
11		49,251	85,051	58,885	62,059
12					
13	**Investing Activities**				
14	Capital expenditures (net of salvage)	(72,167)	(67,333)	(66,855)	(68,195)
15	Long-term portion of finance programs	(84)	35	26	-
16	Contributions from customers and security deposits	2,580	3,227	1,858	2,000
17		(69,671)	(64,071)	(64,971)	(66,195)
18					
19	**Financing Activities**				
20	Change in short-term borrowings	(320)	-	-	-
21	Proceeds from long-term debt	70,000	33,500	65,000	24,770
22	Proceeds from related party loan	-	32,500	-	-
23	Repayment of long-term debt	(37,851)	(39,050)	(33,294)	(5,200)
24	Repayment of related party loan	-	(32,500)	-	
25	Payment of debt financing costs	(273)	(50)	(300)	-
26	Redemption of preference shares	(1)	-	(179)	-
27	Dividends				
28	Preference Shares	(586)	(554)	(579)	(573)
29	Common Shares	(9,082)	(15,274)	(25,181)	(14,861)
30		21,887	(21,428)	5,467	4,136
31					
32	**Change in Cash**	1,467	(448)	(619)	-
33	**Cash (Bank Indebtedness), Beginning of Year**	(400)	1,067	619	-
34	**Cash (Bank Indebtedness), End of Year**	$ 1,067	$ 619	$ -	$ -

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Average Rate Base[1]
($000s)

	Actual		Forecast	
	2007	**2008**	**2009**	**2010E**
Net Plant Investment	683,556	709,493	731,956	754,814
Add:				
Deferred Charges	96,784	98,787	102,342	104,130
Weather Normalization Reserve	11,162	8,214	4,297	2,000
Deferred Energy Replacement Costs	574	957	575	192
Cost Recovery Deferrals	8,690	9,655	6,551	3,447
Customer Finance Programs	1,174	1,794	1,763	1,750
	118,384	119,407	115,528	111,519
Deduct:				
2005 Unbilled Revenue	17,803	12,841	6,927	2,309
Accrued Pension Liabilities	-	3,043	3,261	3,502
Municipal Tax Liability	-	3,408	2,046	683
Future Income Taxes	-	593	2,117	3,228
Demand Management Incentive Account	-	213	213	-
Purchased Power Unit Cost Reserve	1,496	1,272	671	224
Customer Security Deposits	-	697	714	643
	19,299	22,067	15,949	10,589
Average Rate Base Before Allowances	782,641	806,833	831,535	855,744
Cash Working Capital Allowance	6,669	9,716	9,875	10,145
Materials and Supplies Allowance	4,393	4,327	4,432	4,497
Average Rate Base At Year End	793,703	820,876	845,842	870,386

[1] All numbers shown are averages.

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Weighted Average Cost of Capital
($000s)

	Actual		Forecast	
	2007	**2008**	**2009**	**2010E**
Average Capitalization				
Debt	430,924	440,841	453,950	479,623
Preference Shares	9,353	9,352	9,263	9,173
Common Equity	346,279	365,205	377,390	386,307
	786,556	815,398	840,603	875,103
Average Capital Structure				
Debt	54.79%	54.06%	54.00%	54.81%
Preference Shares	1.19%	1.15%	1.10%	1.05%
Common Equity	44.02%	44.79%	44.90%	44.14%
	100.00%	100.00%	100.00%	100.00%
Cost of Capital				
Debt	7.88% [1]	7.72%	7.76%	7.62%
Preference Shares	6.27%	5.92%	6.25%	6.25%
Common Equity	8.66%	9.13%	8.88%	6.87%
Weighted Average Cost of Capital				
Debt	4.32%	4.17%	4.19%	4.18%
Preference Shares	0.07%	0.07%	0.06%	0.06%
Common Equity	3.81%	4.09%	3.99%	3.03%
	8.20%	8.33%	8.24%	7.27%

[1] The cost of debt based upon ARBM would be 8.29%. See Return 25 in the 2008 Annual Report to the P.U.B.

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Rate of Return on Rate Base
($000s)

		Actual		Forecast	
		2007	**2008**	**2009**	**2010E**
1	Regulated Return on Equity	29,977	33,336	33,527	26,559
2	Return on Preferred Equity	586	554	579	573
3		30,563	33,890	34,106	27,132
4					
5	Finance Charges				
6	Interest on Long-term Debt	33,718	32,334	34,604	35,849
7	Other Interest	1,525	1,456	369	461
8	Amortization of Bond Issue Expenses	256	235	234	187
9	Amortization of Capital Stock Issue Expenses	62	-	-	-
10	Interest Earned	(1,477)	-	-	-
11	AFUDC	(622)	(618)	(366)	(374)
12		33,462	33,407	34,841	36,123
13					
14	Return on Rate Base	64,025	67,297	68,947	63,255
15					
16	Average Rate Base	793,703	820,876	845,842	870,386
17					
18	Rate of Return on Rate Base	8.07%	8.20%	8.15%	7.27%

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Inputs and Assumptions

Energy Forecasts : Energy forecasts are based on economic indicators taken from the Conference Board of Canada, Provincial Outlook Spring 2009, Economic Forecast, dated April 21, 2009.

Revenue Forecast : The revenue forecast is based on the Customer, Energy and Demand forecast dated May 2009.

Forecast revenues reflect the (i) amortization of the 2005 Unbilled Revenue, (ii) amortization of the municipal tax liability, (iii) the reclassification of interest on overdue accounts from finance charges, and (iv) recovery through the RSA of amounts associated with the Energy Supply Cost Variance Adjustment Clause for the period 2008 through 2010, all of which were approved by the Board in Order No. P.U. 32 (2007) resulting from the 2008 GRA.

The Energy Supply Cost Variance Adjustment has been approved by the Board for use through 2010.

Purchased Power Expense : Purchased Power expense reflects Newfoundland & Labrador Hydro's rates approved by the P.U.B. and the Customer, Energy and Demand Forecast dated May 2009.

Purchased Power Expense for 2008 to 2010 includes a Board approved $0.6 million per year amortization related to the replacement energy costs associated with the Rattling Brook project and ($0.7) million per year amortization related to the disposition of the Purchased Power Unit Cost Variance Reserve.

Purchased Power Expense for 2008 to 2010 also includes a Board approved $2.1 million per year amortization of the non-reversing balance in the Weather Normalization Reserve.

Purchased Power Expense for the 2008 to 2010 also reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007). This mechanism provides for recovery of demand costs that are in excess of unit cost demand costs included in the 2008 test year.

Employee Future Benefit Costs : Pension costs related to the 2005 Early Retirement Program are being amortized over a 10-year period from 2005 to 2015 as approved in Order No. P.U. 49 (2004).

Pension funding is based on the actuarial valuation dated December 31, 2008 filed with this Application.

Pension expense discount rate is 5.25% for 2007, 5.50% for 2008 and 7.50% thereafter.

Expected return on pension assets is assumed to be 7.0% for 2009 and 2010.

The 2010 forecast assumes that the accounting for OPEBs is on the Cash Basis. The increase in 2010 employee future benefit expense due to the adoption of the accrual method is $5.9 million.

Pension funding is forecast based on the latest actuarial information and assumes special funding payments of $1.5 milllion per year for 2009 and 2010.

Newfoundland Power Inc.

Financial Performance
2007 to 2010E
Inputs and Assumptions

Cost Recovery Deferral: In Order No. P.U. 39 (2006), the Board approved the deferred recovery of $5.8 million in 2007 costs related to the conclusion of the depreciation true up in 2005.

2008 to 2010 costs include $3.9 million per year related to the amortization over a three-year period of cost recovery deferrals related to depreciation.

2009 includes a $1.5 million deferral of Conservation Program costs approved by the Board in Order No. P.U. 13 (2009).

Depreciation Rates : Depreciation rates for 2008 and 2010 are based on the 2006 depreciation study.

Depreciation costs for 2008 and 2010 reflect a Board approved $0.2 million per year amortization of a $0.7 million depreciation true up resulting from the 2006 depreciation study.

Operating Costs : Operating forecasts for 2009 and 2010 reflect the evidence filed in this Application.

Capital Expenditure : Capital Expenditures for 2009 are based on the Board approved 2009 capital budget. Capital Expenditures for 2010 reflect what is included in this Application.

Short-Term Interest Rates : Average short-term interest rates are assumed to be 1.36% for 2009 and 2.0% for 2010.

Long-Term Debt : A $65.0 million long-term debt issue was completed on May 25, 2009. The debt is forecast for 30 years at a coupon rate of 6.606 %. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

Dividends : Common dividend payouts are forecast based on maintaining a target common equity component of 45%.

Income Tax : Income tax expense reflects a statutory income tax rate of 33% in 2009, and 32% in 2010.

Effective July 1, 2008, the Board approved a reduction in customer rates of 0.18% to reflect the 2008 test year income tax true-up adjustment resulting form a reduction in federal tax rates for 2008.

Income tax expense for 2009 to 2010 reflects the tax effecting of pension costs as approved by the Board in Order No. P.U. 32 (2007).

Credit Rating Reports
DBRS and Moody's

Rating Report
Report Date:
May 5, 2008

Previous Report:
March 9, 2007

Newfoundland Power Inc.

Insight beyond the rating.

Analysts
Robert Filippazzo
+1 416 597 7340
rfilippazzo@dbrs.com

Roshan Thiru
+1 416 597 7357
rthiru@dbrs.com

The Company
Newfoundland Power Inc. generates, transmits and distributes electricity. The Company has approximately 233,000 customers throughout the island portion of the province of Newfoundland and Labrador. It purchases more than 90% of its electricity needs from government-owned Newfoundland and Labrador Hydro and generates the balance from its own generation facilities (139 megawatts). Newfoundland Power Inc. is a wholly owned subsidiary of Fortis Inc., a Canadian public holding company focused primarily on electric and gas utility operations in Canada, the Caribbean and the United States.

Rating

Debt	Rating	Rating Action	Trend
First Mortgage Bonds	A	Confirmed	Stable
Preferred Shares – cumulative, redeemable	Pfd-2	Confirmed	Stable

Rating Rationale

DBRS has confirmed the ratings of the First Mortgage Bonds and the Preferred Shares of Newfoundland Power Inc. (Newfoundland Power or the Company) at "A" and Pfd-2, respectively; the trends remain Stable. The rating confirmations reflect Newfoundland Power's low business risk stemming from the regulated nature of its operations and supportive regulatory environment, its strong balance sheet, its stable operating results and its financial profile, as well as its stable customer base, which is composed entirely of residential and commercial customers.

The Company continues to benefit from the following characteristics: (1) a favourable deemed equity ratio of 45%; (2) a weather normalization reserve (WNR) account that is used to stabilize earnings during extreme weather conditions; and (3) a rate stabilization account (RSA) that absorbs fluctuations in purchased power costs relating primarily to the cost of fuel oil for the Company's primary electricity supplier. These features, combined with a stable and supportive regulatory environment that provides for a strong cost-of-service/rate-of-return rate-setting methodology, with a pass-through of all power-generation and procurement-related costs, and a full recovery of all prudently incurred operating expenses and capital expenditures within a reasonable time frame, contribute to the Company's favourable financial profile.

Newfoundland Power continues to demonstrate stable operating results reflective of its expanding customer base and rate base, despite declining regulatory-approved return on common equity (ROE). The prevailing low interest rate environment continues to have a negative impact on the approved ROE, but the impact on earnings and cash flows has been more than offset by the growth in the rate base. During the last 12 months (LTM) ended March 31, 2008, operating results were affected by the change in the seasonality of purchased power costs relative to revenue. Compared with 2007, 2008 interim earnings will be lower in the first (winter) and fourth (fall) quarters and higher in the second (spring) and third (summer) quarters. Annual earnings and annual and quarterly cash flows will be unaffected by this shift. (Continued on page 2.)

Rating Considerations

Strengths
(1) Stable and supportive regulatory environment
(2) Strong balance sheet and favourable financial profile
(3) Stable customer base
(4) Limited competition from alternative fuels

Challenges
(1) Reliance on Newfoundland and Labrador Hydro (NLH) for majority of power supply
(2) Allowed returns are sensitive to interest rates
(3) Managing forecast risk
(4) Limited growth potential

Financial Information

	For the 12-month periods ended					
($ millions)	Mar. 31/08	Dec. 31/07	Dec. 31/06	Dec. 31/05	Dec. 31/04	Dec. 31/03
EBIT	70.4	76.1	77.0	76.0	77.7	75.1
Free cash flow	(34.5)	(30.0)	(18.8)	(10.9)	(12.9)	(23.6)
Total debt in the capital structure (1)	56.1%	55.1%	55.0%	54.7%	54.7%	55.1%
Cash flow/total debt (1)	11.1%	11.6%	12.7%	14.2%	14.9%	14.0%
Fixed-charges coverage (times)	1.96	2.11	2.20	2.27	2.40	2.33
Dividend payout ratio	41.5%	30.4%	60.4%	78.8%	45.7%	32.2%

(1) Total debt adjusted for preferred shares.

Rating Rationale (Continued from page 1.)

Capital expenditures prior to 2007 were relatively stable as a result of a multi-year capital investment program that was launched in 2002 with the primary focus of replacing and refurbishing aging infrastructure. The substantially higher capital expenditure witnessed in 2007 is primarily due to the successful refurbishment of the Rattling Brook Hydroelectric Plant, which resulted in improved plant capacity and production. The manageable free cash flow deficit stemmed from the elevated capital expenditure levels and dividend payments. The Company has historically utilized its credit facilities to finance the free cash flow shortfalls as a bridge to the issuance of First Mortgage Bonds. The Company manages the level of its dividends in order to maintain its long-term capital structure of 55% debt to 45% equity, as approved by the regulator. DBRS notes that while the Company's credit metrics appear weaker than those of its peers in the same rating category, this is offset by the Company's very stable levels of EBITDA and cash flow.

In December 2007, the Company received an order from its regulator, the Newfoundland and Labrador Board of Commissioners of Public Utilities (the PUB), on its 2008 General Rate Application (the 2008 GRA Order), which proposed an average increase in customer rates of 2.8% effective January 1, 2008. The rate increase is based upon a 2008 rate of return on common equity of 8.95% as opposed to the 8.60% for 2007. The 2008 GRA Order also provides for the amortization of certain regulatory assets and liabilities (e.g., unbilled revenue liability and true-up deferrals) over periods of three to five years beginning in 2008. The rate increase is expected to yield EBITDA and cash flows that will have a positive impact on the financial profile and credit metrics of the Company.

Pending PUB approval on July 1, 2008, there will be an overall average increase in electricity rates charged to customers of approximately 6%. The increase is a result of the normal annual operation of NLH's RSA. This increase in customer rates will have no impact on earnings and cash flows for Newfoundland Power.

Although Newfoundland Power does have strong parentage through Fortis Inc. (Fortis, rated BBB (high) with a Stable trend; see the November, 30, 2007, DBRS rating report), the Company is largely rated on a stand-alone basis. Fortis is a large, integrated electric and gas utility holding company that has the financial wherewithal to provide equity support if required by Newfoundland Power.

Rating Considerations Details

Strengths

(1) Newfoundland Power operates in a stable and supportive regulatory environment that is based on a cost-of-service recovery regime. The PUB allows for the pass-through of purchased power costs, and in addition, a RSA is in place that absorbs fluctuations in purchased power costs relating primarily to the cost of fuel oil used by NLH to generate electricity. The Company has a PUB-approved WNR account that stabilizes earnings by adjusting revenue and purchased power expenses for variances in weather and stream flow when measured against long-term averages.

(2) The Company has a strong balance sheet with a capital structure based on the 45% equity component allowed by the PUB for rate-setting purposes. The Company's financial profile is strong, with manageable free cash flow deficits as the Company invests to upgrade its infrastructure. Key credit ratios have modestly trended downward in recent years; however, they remain in line with the current rating category. Given the Company's January 1, 2008, rate increase, the metrics are expected to improve over the medium term. Furthermore, the Company has shown that it will manage its dividend policy as necessary in order to maintain its approved capital structure, as evidenced by the scaling back of dividends in several of the last five years.

(3) Newfoundland Power also has a very stable customer base, with 100% of power sales to the residential and commercial segments. The large industrial customers are served primarily by NLH. Sales growth is modest, reflecting slow growth in customers as well as increasing conservation efforts. However, approximately 83% of new home construction installed electric heat in 2007.

(4) The lack of availability of natural gas, due to geographic isolation and the lack of related infrastructure, also limits competitive pressures. More than 50% of the Company's current customers utilize electric space heating, causing electricity sales to be much higher during the winter months than in the summer.

Challenges

(1) Newfoundland Power relies heavily on NLH (rated A (low) with a Positive trend; see the November 16, 2007, DBRS rating report) for its power supply, purchasing more than 90% of its power requirements. The cost of power purchased from NLH is influenced by, among other things, the market price of bunker C fuel oil used for thermal generation. Oil-driven changes in the cost of power are passed onto Newfoundland Power's customers through the RSA. However, higher rates, including increases driven by the rising cost of oil in recent years, may lead to energy conservation by customers, which could have a negative impact on sales volumes and ultimately earnings. Furthermore, higher NLH rates could make it more difficult for the Company to get approval for its own rate increases.

(2) Under the current regulatory regime, the rate-setting ROE, and hence earnings, are sensitive to interest rates. Between test years, the rate-setting ROE is set by an automatic-adjustment formula and based on a ten-day average (calculated in November) yield on long-term Government of Canada bonds, which does not capture any expected upward trend in interest rates (as would be the case with utilizing a consensus forecast interest rate). The prevailing low interest rate environment continues to affect approved ROEs. Lower ROEs have a negative impact on earnings and cash flows. Pursuant to the 2008 GRA Order, the rate-setting ROE for 2008 increased modestly to 8.95% from 8.60% in 2007. DBRS estimates this, along with rate base growth, will positively affect after-tax earnings by approximately $1.3 million for 2008.

(3) The key challenge with respect to the Demand Management Incentive Account (DMIA) will be the Company's ability to accurately and consistently forecast electricity demand going forward. However, through this account, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs ($529,000 for 2008). The disposition of the excess balances, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities. The Company is required to make an application no later than March 1 each year for the disposition of any balance in the DMIA. (See the Regulation section for more information on the DMIA.)

(4) The Newfoundland economy is heavily dependant on the more volatile natural resources sectors. Over the medium term, natural resources development (which has been highly favourable up until now) will continue to have a major impact on economic growth. However, the Company expects that service sector growth, which is the primary influence on sales growth for the Company, will grow by 1.9% and contribute to an electricity consumption growth of 2.4% in 2008. Additionally, rural out-migration has caused the population of Newfoundland and Labrador to decline by more than 11.5% since 1992, and declining birth rates, coupled with increasing death rates associated with an aging population, continue to have a negative impact on the Company's customer and energy sales growth.

Newfoundland Power Inc.

Report Date:
May 5, 2008

Earnings and Outlook

Earnings

($ millions)	For the 12-month periods ended Mar. 3/08	Dec. 31/07	Dec. 31/06	Dec. 31/05	Dec. 31/04	Dec. 31/03
Revenues	500.3	490.2	421.3	417.9	404.5	384.2
EBITDA	104.4	110.3	110.1	108.1	108.7	104.4
EBIT	70.4	76.1	77.0	76.0	77.7	75.1
Gross interest expense	35.1	35.2	34.1	32.6	31.4	31.3
Core net income	26.1	30.5	30.7	29.9	31.8	30.1
Net income (reported)	25.6	29.9	30.1	30.7	31.2	29.5
Return on average common equity	7.3%	8.8%	9.3%	9.3%	10.3%	10.4%
Rate base	812	794	753	745	715	676
Growth in rate base	2.3%	5.4%	1.0%	4.3%	5.8%	18.0%
Rate setting common equity	45%	45%	45%	45%	45%	45%
Rate setting ROE	8.95%	8.60%	9.24%	9.24%	9.75%	9.75%

Summary

LTM March 31, 2008, operating results were affected by the change in the seasonality of purchased power costs relative to revenue. Compared with 2007, 2008 interim earnings will be lower in the first (winter) and fourth (fall) quarters and higher in the second (spring) and third (summer) quarters. Annual earnings and annual and quarterly cash flows will be unaffected by this shift.

Newfoundland Power has historically demonstrated strong and stable EBITDA and EBIT, reflective of its expanding customer base and rate base, despite declining rate-setting ROEs. Its operations are 100% regulated, providing strong stability to earnings, which is further increased due to a favourable customer base composed entirely of residential and commercial customers. The large industrial customers in the province are served by NLH.

The prevailing low interest rate environment continues to have a negative impact on the rate-setting ROEs, but the impact on earnings and cash flows have been more than offset by the growth in the rate base. The impact of power price volatility on earnings is limited as costs related to power procurement are passed on to customers, albeit with some regulatory lag.

Interest expenses have increased over time as a result of increased borrowings to finance the Company's capital expenditure programs.

Outlook

Pursuant to the 2008 GRA Order, the Company's rate-setting ROE was increased from 8.60% to 8.95%. DBRS believes that the increase in rate-setting ROE, coupled with the growth in rate base, will have a positive impact on the after-tax earnings by approximately $1.3 million. DBRS anticipates EBITDA and net income to grow over the medium term, primarily driven by the growth in rate base related to the ongoing capital projects, as well as economic expansion in the Company's service area and modest housing starts, somewhat tempered by the declining population within the rural portion of the service territory. As such, key credit metrics are expected to improve along with earnings.

Financial Profile

($ millions)	For the 12-month periods ended					
Cash Flow Statement	Mar. 31/08	Dec. 31/07	Dec. 31/06	Dec. 31/05	Dec. 31/04	Dec. 31/03
Core net income	26.1	30.5	30.7	29.9	31.8	30.1
Depreciation and amortization	32.4	35.1	34.6	34.3	31.6	28.9
Other non-cash adjustments	(6.6)	(13.8)	(12.1)	(7.6)	(5.3)	(6.3)
Cash Flow from Operations	51.9	51.8	53.1	56.6	58.1	52.7
Dividends	(11.2)	(9.7)	(18.8)	(23.7)	(14.8)	(10.1)
Capital expenditures (1)	(70.0)	(69.6)	(57.1)	(53.7)	(58.9)	(63.0)
Free Cash Flow before W/C Changes	(29.3)	(27.5)	(22.7)	(20.8)	(15.6)	(20.4)
Net changes in working capital	(5.2)	(2.6)	3.9	9.8	2.7	(3.3)
Net Free Cash Flow	(34.5)	(30.0)	(18.8)	(10.9)	(12.9)	(23.6)
Other investing activities	(0.2)	(0.1)	(0.3)	(0.4)	0.2	(0.1)
Other & adjustments	0.0	0.0	0.0	1.4	0.0	0.0
Amount to be Financed	(34.7)	(30.1)	(19.0)	(9.9)	(12.7)	(23.7)
Net debt financing	35.4	31.6	19.5	8.7	14.6	20.3
Net preferred financing	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.3)
Net common equity	0.0	0.0	0.0	0.0	0.0	0.0
Net Change in Cash	0.7	1.5	0.4	(1.2)	1.8	(3.7)
% adjusted debt in capital structure	56.1%	55.1%	55.0%	54.7%	54.7%	55.1%
Fixed-charges coverage (times)	1.96	2.11	2.20	2.27	2.40	2.33
Cash flow/adjusted debt	11.1%	11.6%	12.7%	14.2%	14.9%	14.0%
Adjusted debt-to-EBITDA (times)	4.47	4.05	3.80	3.69	3.58	3.60
Dividend payout ratio	41.5%	30.4%	60.4%	78.8%	45.7%	32.2%

(1) Net of contributions from customers and security deposits.

Summary

Newfoundland Power has maintained a strong financial profile, reflecting solid balance sheet and credit metrics. Cash flows from operations have historically displayed the same underlying stability as EBITDA, reflecting the regulated nature of the Company's operations with modest variability due to annual regulatory deferrals. While the Company's credit metrics appear weaker than those of its peers in the same rating category, this is offset by the Company's more stable credit metrics and business risk profile.

Capital expenditures, although elevated in 2007, have been relatively stable since 2002 as a result of a multi-year capital investment program that was launched in that year with the primary focus of refurbishing and replacing aging and deteriorated infrastructure. The elevated level of capital expenditures in 2007 is primarily due to the refurbishment of the Rattling Brook Hydroelectric Plant. The Company successfully completed that project in November 2007, which resulted in improved plant production of 9%, from 69.8 to 76.0 gigawatt hours (GWh) and improved plant capacity of 26%, from 11.2 to 14.1 megawatts (MW).

Although the Company continues to maintain strong and stable cash flow from operations, capital investments continue to cause free cash flow deficits. The Company has historically utilized its credit facilities to finance the free cash flow shortfalls as a bridge to the issuance of First Mortgage Bonds. The Company manages the level of its dividends in order to maintain a long-term capital structure of 55% debt and 45% equity, as approved by the PUB for rate-setting purposes. Although leverage has remained relatively unchanged at approximately 55% since the beginning of the capital program, coverage ratios have trended downward in recent years due to lower rate-setting ROEs and increased debt levels, which were needed to fund the ongoing capital expenditure program.

Outlook

The January 1, 2008, rate increase is expected to have a positive impact on the cash flow from operations. However, fairly modest free cash flow deficits are expected to persist over the 2008–2010 period, reflecting the ongoing capital investment program.

Newfoundland Power Inc.

Report Date:
May 5, 2008

The Company's PUB-approved capital budget for F2008 is approximately $51 million. The focus will be on the replacement of aging infrastructure to strengthen the electricity system and the Company's obligation to meet the demands of customer and electricity sales growth. Capital expenditures over the 2008–2010 period are expected to be between $55 million and $60 million annually. DBRS expects the Company to continue funding cash flow shortfalls with borrowings under its credit facilities, with long-term debt issuances and through the management of dividends.

DBRS expects the growth in earnings and cash flows from operations to have a positive impact on the key credit metrics and the Company's financial profile over the 2008–2010 period. However, the Company's credit profile beyond 2010 is expected to largely depend on its future rate applications to the PUB. Newfoundland Power's financial profile is considered to be favourable, with reasonable leverage in line with the regulatory-approved capital structure and key credit ratios in line with the current rating.

Long-Term Debt Maturities and Liquidity

($ millions)	2008	2009	2010	2011	2012	Thereafter	Total
Long-term bonds	4.6	4.6	4.6	4.6	4.6	391	414
Credit facilities	0	53.0	0	0	0	0	53
as at Mar. 31, 2008	4.6	57.6	4.6	4.6	4.6	390.9	467

Debt Chart

Securities outstanding		**Mar. 31, '08**
First mortgage sinking fund bonds:		
2014	10.55%	31.4
2016	10.90%	33.6
2022	10.13%	34.0
2020	9.00%	34.8
2026	8.90%	35.6
2028	6.80%	45.5
2032	7.52%	71.3
2035	5.44%	58.2
2037	5.90%	69.3
		414
Credit facilities		53
Subtotal		467
Less: current portion		58
		409

Newfoundland Power's debt consists of $414 million in First Mortgage Bonds and $53 million in unsecured credit facilities. The First Mortgage Bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.

Newfoundland Power has the following credit facilities available:

- A three-year $100 million syndicated, committed revolving unsecured credit facility expiring in January 2009.
- A $20 million uncommitted demand facility.

As at March 31, 2008, $53 million was outstanding on the Company's $100 million credit facility. The credit facilities contain a covenant that provides that the Company shall not declare or pay any dividends or make any other restricted payments if immediately thereafter the debt-to-capitalization exceeds 65%.

The Company is also restricted under its Trust Deed to meet specific tests when it intends to issue additional long-term bonds. The Company must meet an Earnings Test where the net earnings, in a period of any 12 consecutive months terminating within 24 months preceding the delivery of such additional bonds, are at least two times the annual interest charges on all bonds outstanding after any proposed additional bond issue. Secondly, the Company must meet the Additional Property Test, whereby the additional bonds must not exceed 60% of the fair value of the additional property.

Outlook
The debt-repayment schedule is very modest, with the exception of the $53 million under the bank credit facility that matures along with the facility in January 2009. The Company has indicated that it will extend or replace the facility before the expiry in January 2009. The $53 million outstanding under the credit facilities is expected to be refinanced with long-term financing during future periods. Given funds available under the credit facilities and stable cash flows from operations, liquidity remains more than adequate to fund both working capital requirements and cash flow deficits.

Description of Operations

Newfoundland Power generates, transmits and distributes electricity. The Company has approximately 233,000 customers throughout the island portion of the province of Newfoundland and Labrador; approximately 60% of electricity sales are to the residential segment, with the remainder sold to commercial customers and for street lighting. As a result, total sales have shown strong stability, with modest growth year over year.

The Company's generating capacity consists of 23 hydroelectric stations and seven thermal plants, with a total installed capacity of 139 MW. Approximately 90% of power requirements are sourced from NLH. The principal terms of the supply agreement are regulated by the PUB on a similar basis to that of the Company's customers.

Regulation

Regulatory Overview
Newfoundland Power is regulated by the PUB, which is authorized to set electricity rates and the capital structure and ROE for rate-setting purposes, as well as approve capital expenditures. Rates are based on a cost-of-service/rate-of-return methodology. Newfoundland Power has a favourable rate-setting equity component of 45%.

An automatic-adjustment formula, applied annually between test years in November, is used to determine customer rates, effective January 1 of the following year, by adjusting the allowed return-on-rate base to reflect changes in the allowed ROE attributable to movements in long-term Government of Canada bond yields. The Company's allowed ROE is based on a ten-day average of the three most recent series of long-term Government of Canada bonds plus the test-year risk premium. The allowed return-on-rate base and customer rates are adjusted if the rate of return-on-rate base indicated by the formula falls outside the approved range (+/- 18 basis points). Pursuant to the 2008 GRA Order, the PUB approved continued use of the automatic-adjustment formula for setting rates in 2009, 2010 and 2011.

Pursuant to the 2008 GRA Order, customer rates increased by an average of approximately 2.8% effective January 1, 2008. This increase reflects an increase of the Company's ROE for the purpose of setting rates from 8.60% in 2007 to 8.95% in 2008. The 2008 GRA Order also provides for the amortization of certain regulatory assets and liabilities. The rate increase is expected to yield EBITDA and cash flows that will have a positive impact on the financial profile and credit metrics of the Company. The Company does not expect to file its next GRA until at least 2010 to set customer rates for 2011.

Given that the Company's rates are based on estimates of several items, such as electricity sales volumes and the cost of purchasing electricity, in order to manage the risks associated with some of these estimates, a number of deferral accounts are in place.

- **Weather Normalization Reserve (WNR):** The WNR reduces earnings volatility by adjusting electricity purchases and sales to eliminate variances caused by the difference between normal weather conditions, based on long-term averages, and actual weather conditions.
- **Rate Stabilization Account (RSA):** The RSA flows amounts related to changes in the cost and quantity of fuel burned by NLH to produce the electricity sold to the Company through to the Newfoundland Power's customers. On July 1 of each year, customer rates are re-calculated in order to amortize over the subsequent 12 months the balance in the RSA as of March 31 of the previous year. In the 2008 GRA Order, the PUB approved the recovery of energy-supply cost variances through the RSA until the end of 2010. The energy-supply cost variance is the difference between the incremental rate the Company pays for purchasing energy and the average supply cost reflected in rates. The incremental cost to purchase energy currently exceeds the revenue the Company can expect to receive on incremental sales above the forecast used to set customer rates. Recovery of the energy-supply cost variance provides the Company a reasonable opportunity to recover supply costs without requiring a GRA. The recovery of the energy-supply cost variance through the RSA is complimentary to the DMIA.
- **Demand Management Incentive Account (DMIA):** In December 2005, the PUB approved the creation of a Purchased Power Unit Cost Variance Reserve (PPUCVR) in association with the implementation of the demand and energy rate structure for the energy Newfoundland Power purchases from NLH. The PPUCVR was approved as a temporary reserve to limit the volatility on purchased power costs caused by variances between the actual unit cost of purchased power (per kilowatt hour) and the forecast unit cost of purchased power (per kilowatt hour) during the three-year phase-in of the new purchased power rate structure beginning in 2005. The Company will apply to the PUB in 2008 to dispose of the amount owed to customers resulting from operation of the PPUCVR for 2007. Effective January 1, 2008, the PUB has ordered the discontinuance of the PPUCVR and the creation of the DMIA. Through this account, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs ($529,000 for 2008) reflected in customer rates. Balances in this account will be shown as a regulatory asset or liability on Newfoundland Power's balance sheet. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities. The Company is required to make an application no later than March 1 of each year for the disposition of any balance in the DMIA. The elimination of PPUCVR and the creation of the DMIA are not expected to have a material impact on the Company's earnings and cash flows.

Newfoundland Power Inc.

Report Date:
May 5, 2008

Newfoundland Power Inc.

Balance Sheet	As at				As at		
($ millions)	Mar. 31/08	Dec. 31/07	Dec. 31/06	**Liabilities & Equity**	Mar. 31/08	Dec. 31/07	Dec. 31/06
Assets				Short-term debt	-	-	0.7
Cash + equivalents	0.9	1.1	-	Debt due one yr.	57.6	4.6	35.7
Accounts receivable	87.5	70.8	61.6	A/P + accr'ds	66.1	68.7	65.2
Inventories	5.7	5.2	4.9	Other	8.4	9.3	3.0
Prepaids & other	9.9	10.1	6.7	**Current Liabilities**	132.1	82.6	104.6
Current Assets	104.0	87.2	73.3	Long-term debt	406.0	439.0	378.8
Net fixed assets	750.0	746.5	717.1	Deferred & other	99.2	98.4	100.5
Regulatory assets	59.0	61.8	52.9	Preferred equity	9.4	9.4	9.4
Deferred charges & other	92.7	90.5	85.9	Shareholders' equity	359.1	356.7	335.9
Total	1,005.7	985.9	929.2	**Total**	1,005.7	985.9	929.2

Ratio Analysis	For the 12-month periods ended					
Liquidity Ratios	Mar. 31/08	Dec. 31/07	Dec. 31/06	Dec. 31/05	Dec. 31/04	Dec. 31/03
Current ratio	0.79	1.06	0.70	1.00	0.59	0.44
Acc. depreciation/gross fixed assets	36.2%	36.2%	36.0%	40.0%	40.0%	40.4%
Cash flow / adjusted debt (1)	11.1%	11.6%	12.7%	14.2%	14.9%	14.0%
Cash flow / CAPEX	74.2%	74.4%	93.1%	105.5%	98.7%	83.7%
(Cash flow - Dividends) / CAPEX	58.2%	60.6%	60.2%	61.3%	73.5%	67.7%
% debt in capital structure	55.7%	54.8%	54.6%	54.3%	54.3%	54.7%
% adjusted debt in capital structure (1)	56.1%	55.1%	55.0%	54.7%	54.7%	55.1%
Max. equity for rate setting purposes	45%	45%	45%	45%	45%	45%
Common dividend payout ratio	41.5%	30.4%	60.4%	78.8%	45.7%	32.2%
Coverage Ratios						
EBIT interest coverage	2.00	2.16	2.26	2.33	2.47	2.40
EBITDA interest coverage	2.97	3.13	3.23	3.32	3.46	3.34
Fixed-charges coverage	1.96	2.11	2.20	2.27	2.40	2.33
Adjusted debt / EBITDA (1)	4.47	4.05	3.80	3.69	3.58	3.60
Earnings Quality/Operating Efficiency						
Power purchases/revenues	68.6%	66.7%	61.0%	61.3%	61.7%	60.6%
EBIT margin	14.1%	15.5%	18.3%	18.2%	19.7%	20.0%
Net margin (before extras)	5.2%	6.2%	7.3%	7.2%	8.0%	8.0%
Return on avg. equity (bef. extras)	7.3%	8.8%	9.3%	9.3%	10.3%	10.4%
Allowed ROE – mid-point	8.95%	8.60%	9.24%	9.24%	9.75%	9.75%
Growth of customer base	1.7%	1.2%	1.0%	1.3%	1.3%	1.2%
Rate base ($ millions)	812	794	753	745	715	676
Growth in rate base	2.3%	5.4%	1.0%	4.3%	5.8%	18.0%

(1) Preferred shares are considered to be 70% equity, 30% debt

Newfoundland Power Inc.

Report Date:
May 5, 2008

Summary of Operating Statistics

Electricity Sales - Breakdown (GWh)		For the 12-month periods ended Mar. 31/08	Dec. 31/07	Dec. 31/06	Dec. 31/05	Dec. 31/04	Dec. 31/03
Residential	60%	3,081	3,044	2,981	2,987	2,972	2,909
General service	40%	2,066	2,049	2,014	2,017	2,007	1,973
Total sales		5,147	5,093	4,995	5,004	4,979	4,882
Growth in volume throughputs		1.1%	2.0%	-0.2%	0.5%	2.0%	2.5%
Customers							
Residential	87%	201,815	201,045	198,568	196,412	193,912	191,314
Commercial	13%	31,421	31,217	30,932	30,889	30,552	30,339
Total		233,236	232,262	229,500	227,301	224,464	221,653
		0.4%	1.2%	1.0%	1.3%	1.3%	1.2%

Energy Generated (GWh)		For the 12-month periods ended Mar. 31/08	Dec. 31/07	Dec. 31/06	Dec. 31/05	Dec. 31/04	Dec. 31/03
Energy generated	7%	383	381	417	426	424	425
Energy purchased	93%	5,067	5,013	4,876	4,873	4,841	4,725
Energy generated + purchased		5,450	5,394	5,293	5,299	5,265	5,150
Less: transmission losses + internal use		304	301	298	295	286	268
Total sales		5,146	5,093	4,995	5,004	4,979	4,882
System losses and internal use		5.9%	5.9%	6.0%	5.9%	5.7%	5.5%
Installed Generation Capacity (MW)							
Hydroelectric		96	96	92	95	95	95
Gas turbine		37	37	37	44	44	44
Diesel		7	7	7	7	7	6
Total		139	139	136	146	146	144
Peak demand (MW)		1,188	1,142	1,166	1,124	1,167	1,118

Newfoundland Power Inc.

Report Date:
May 5, 2008

Rating

Debt	Rating	Rating Action	Trend
First Mortgage Bonds	A	Confirmed	Stable
Preferred Shares – cumulative, redeemable	Pfd-2	Confirmed	Stable

Rating History

	Current	2007	2006	2005	2004	2003
First Mortgage Bonds	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Related Research

- DBRS Confirms Newfoundland Power Inc., April 30, 2008.
- Newfoundland and Labrador Hydro, November 16, 2007.
- Fortis Inc., November, 30, 2007.

Notes:
All figures are in Canadian dollars unless otherwise noted.

Credit Opinion: Newfoundland Power Inc.

Newfoundland Power Inc.

Canada

Ratings

Category	Moody's Rating
Outlook	Stable
First Mortgage Bonds -Dom Curr	Baa1

Contacts

Analyst	Phone
Allan McLean/Toronto	416.214.3852
William L. Hess/New York	212.553.3837

Key Indicators

Newfoundland Power Inc.

	2008	2007	2006	2005	2004
(CFO Pre-W/C + Interest Expense) / Interest Expense (x) [1][2]	**3.1x**	**2.6x**	**2.7x**	**2.9x**	**3.0x**
(CFO Pre-W/C) / Debt (%) [1]	**15.8%**	**12.6%**	**13.9%**	**15.7%**	**16.0%**
(CFO Pre-W/C - Dividends) / Debt (%) [1]	**12.4%**	**10.6%**	**9.6%**	**10.1%**	**12.5%**
Debt / Book Capitalization (%)	**54.4%**	**55.9%**	**55.8%**	[3]**63.18%**	**55.5%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Interest includes implied interest on operating leases and capital interest. [3] In 2005, NPI's defined benefit plan underfunding resulted in Moody's standard balance sheet adjustments which reduced its capitalization by approximately $58 million, leading to an increase in the Debt/ Book Capitalization ratio. In the absence of any adjustments, Debt/Book Capitalizaton would have been 54.2%

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk regulated electric utility operating in a relatively supportive regulatory environment.

Credit metrics expected to strengthen but continue to remain somewhat weaker than those of other Baa1-rated, lower risk utilities.

Relatively moderate capital expenditures and dividends resulting in modest negative free cash flow deficits.

Strong liquidity arrangements for a company of its rate base and current level of capital spending.

Company Profile

Headquartered in St. John's, Newfoundland, Newfoundland Power Inc. (NPI) is a vertically integrated electric utility that operates under cost of service regulation as administered by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) under the Public Utilities Act (the Act). NPI is a wholly-owned subsidiary of Fortis Inc. (FTS), a diversified electric and gas utility holding company also based in St. John's, Newfoundland.

SUMMARY RATING RATIONALE

The Baa1 rating of NPI's senior secured First Mortgage Bond (FMB) debt reflects the company's relatively low business risk as a cost-of-service regulated, predominately transmission and distribution (T&D) utility with no unregulated business activities. Approximately 92% of NPI's power requirements are purchased from provincially-owned Newfoundland & Labrador Hydro (Hydro), the cost of which are passed through to ratepayers. The balance is produced by NPI's own generation assets which are regulated and represent less than 15% of NPI's property, plant and equipment. Accordingly, Moody's considers NPI's business risk profile to be more like that of a transmission and distribution utility than a vertically integrated utility.

The improvement in NPI's credit metrics that occurred during 2008 is expected to be sustainable although the company's metrics remain somewhat weaker than those of other Baa1-rated low risk regulated utilities. Moody's believes that NPI's somewhat weaker metrics are balanced by NPI's supportive regulatory environment. Moody's considers the PUB to be one of the more supportive regulators in Canada and notes that NPI's 45% deemed equity component is among the highest for Moody's-rated electric utilities in Canada and that its 2009 allowed ROE is 8.95%.

NPI's capital spending is forecasted to remain relatively moderate for the next several years resulting in only modest free cash flow deficits. While NPI has ongoing sinking fund requirements, these are considered manageable and the company has no scheduled FMB maturities until 2014. In this context, NPI's liquidity is considered to be relatively strong.

DETAILED RATING CONSIDERATIONS

LOW-RISK BUSINESS MODEL LOCATED IN A SUPPORTIVE REGULATORY AND BUSINESS ENVIRONMENT

NPI's rating reflects the company's low business risk as a cost of service-regulated monopoly utility. NPI owns and operates a vertically integrated electric utility located on the island portion of Newfoundland and dominates that market, serving roughly 85% of the electricity customers on the island. The market is geographically isolated and effectively insulated from potential competition. As well, the market is mature and has tended to grow at a relatively low and predictable rate of about 1 to 2% annually. Historically, growth has therefore not taxed NPI either operationally or financially. Although NPI is notionally vertically integrated, it is predominantly a transmission and distribution utility since its generation assets provide only about 8% of the electricity that NPI delivers. Moody's considers the T&D segment to be a relatively lower risk segment of the electric utility industry since it is typically not exposed to commodity price and volume risks or the operational, financial and environmental risks associated with electricity generation.

All of NPI's operations are located in Canada whose regulatory and business environments Moody's considers to be relatively supportive. Moody's considers the PUB to be one of the more supportive regulators in Canada and notes that NPI's 45% deemed equity component is among the highest for Moody's-rated electric utilities in Canada and that its 2009 allowed ROE remains at 8.95%. The Baa1 rating assigned to NPI's FMB debt also reflects the first mortgage security over NPI's property, plant and equipment. All assets are pledged as security and all current and future FMB issuances must be in support of prudently-incurred costs and must be pre-approved by the PUB.

IMPROVEMENT OF CREDIT METRICS EXPECTED TO BE SUSTAINABLE BUT METRICS REMAIN SLIGHTLY WEAKER THAN THOSE OF Baa1-RATED PEERS

NPI's credit metrics in 2008 demonstrated improvement primarily as a result of a 2.8% average rate effective January 1, 2008. However, NPI's ratios generally continue to be somewhat weaker than those of other Baa1-rated peers predominantly engaged in T&D such as Atlantic City Electric Company (ACE), Connecticut Light and Power Company (CLP) and FortisAlberta Inc. (FAB, a sister company). ACE and FAB have reported CFO pre-WC to debt in the 15 to 20% range versus NPI's roughly 15% level. Similarly, ACE, CLP and FAB have reported CFO pre-WC interest coverage in the range of 4x versus NPI's sub-3x range in recent years. In general, Moody's anticipates that NPI's CFO pre-WC to debt will remain in the 15 to 16% range while its CFO pre-WC interest coverage stays above 3x going forward.

NPI's relatively weaker financial profile is offset by the company's location in a supportive regulatory environment with a regulatory construct that permits it to over or under earn within a band of plus or minus 18 basis points of its allowed return on ratebase. Historically, NPI has been able to achieve returns in excess of its allowed ROE. Two key features of NPI's regulatory regime which facilitate timely recovery of the company's costs are the rate stabilization clause which includes 1) a mechanism for tracking energy supply cost variances and 2) a demand management incentive account which includes a mechanism for tracking demand supply cost variances. Together, these mechanisms limit NPI's ultimate exposure to fluctuations in purchased power costs related to volatility in commodity prices and variations in customer demand to approximately $500,000 annually. In the absence of the rate stabilization mechanism, NPI would be exposed to, among other things, volatility in the price of power purchased from Hydro due principally to fluctuations in the price of fuel oil burned at Hydro's Holyrood thermal generating station. Among other things, the rate stabilization clause permits NPI to recover or refund variations in the energy component of power purchased from Hydro on a lagged basis. Recognizing that purchased power is NPI's single largest expense, the rate stabilization and demand management incentive mechanisms are significant risk mitigants. Moody's notes, however, that the energy supply cost variance mechanism is approved to the end of 2010 at which time NPI will have to apply for an extension or request an alternative mechanism.

MODEST CAPITAL EXPENDITURE PROGRAM AND BENIGN DEBT MATURITY PROFILE NOT EXPECTED TO TAX LIQUIDITY RESOURCES

Unlike many utilities, NPI's future capital spending requirements are relatively modest as growth within its franchise is relatively low and predictable. In addition, the company has no scheduled FMB maturities until 2014 and required sinking fund payments of roughly $4.5 million annually are relatively minor. Like most utilities, NPI is expected to be free cash flow negative in most years but given its modest capital spending forecast and benign maturity profile, the company's financing requirements are not expected to be stressful.

Moody's believes that the PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly limits the possibility of cost disallowances or the inability to fully recover costs on a timely basis. NPI submits its proposed capital plan for PUB approval annually. Furthermore, NPI is required to obtain PUB pre-approval for the issuance of any FMBs or the incurrence of credit facilities with maturities exceeding one year

NPI IS OPERATIONALLY AND FINANCIALLY INDEPENDENT OF FTS AND ITS SUBSIDIARIES

While NPI is one of a number of utility operating companies owned by Fortis, Moody's considers NPI, like sister companies FortisAlberta Inc., FortisBC Inc., Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., to be operationally and financially independent from Fortis. Fortis has consistently demonstrated good management and support of its subsidiaries and Moody's considers NPI's access to the executive and strategic support of Fortis to be a credit positive.

Liquidity Profile

NPI's liquidity arrangements are considered strong in the context of its modest capital spending plans and limited sinking fund requirements. In evaluating a company's liquidity, Moody's typically assumes that the company loses access to new debt capital, other than credit available under its committed credit agreements, for a period of 12 months. In this context, we then evaluate the company's various sources and uses of cash including the flexibility to defer or reduce uses of cash such as capital expenditures and dividends.

The company's core liquidity facility is a $100 million syndicated committed revolving credit facility that is scheduled to mature on August 29, 2011. This facility provides NPI with the ability to request on the first anniversary date, an extension of the then-current maturity date by an additional 364 days or on the second anniversary date, an extension of the then-current maturity date by what amounts to an additional two years. Any such extensions are subject to the consent of the banks. While the credit agreement contains a covenant that NPI maintains its debt to capitalization ratio at or below 65%, the credit agreement no longer includes funding inhibiting language such as a material adverse change (MAC) default or representation and warranty prior to drawdowns. At December 31, 2008, NPI appeared to have sufficient headroom under the debt to capitalization covenant since its actual debt to capitalization was approximately 53%. As of December 31, 2008, approximately $68 million was available to NPI under its committed credit facility.

NPI is expected to generate approximately $70 million of adjusted funds from operations (FFO) in 2009. After dividends in the range of $25 million and capital expenditures plus working capital changes of approximately $65 million, Moody's expects NPI to be free cash flow (FCF) negative by approximately $20 million in 2009. The majority of NPI's long-term debt is in the form of FMBs and Moody's expects that NPI will periodically issue additional FMBs to reduce outstandings under its bank credit facility and to refinance scheduled debt maturities. NPI has indicated in its 2008 financial statements that it expects to issue FMBs during 2009. While NPI has $4.5 million of sinking fund requirements during 2009, the next scheduled FMB maturity is not until 2014. Accordingly, we expect that the amounts available to NPI under its committed bank facility will be more than sufficient to meet its funding requirements during 2009 if it decides not to issue additional FMBs.

In the event that NPI encountered an unforeseen cash flow constraint, Moody's notes that NPI has some flexibility to manage capital outflows as we understand that a majority of its planned capital expenditures are maintenance related and therefore could be deferred for a period of time. Furthermore, as a privately-owned entity, NPI has more flexibility than an investor-owned utility to curtail its dividend payments.

Rating Outlook

The rating outlook is stable based on the expectation that the improvement in NPI's key cash flow metrics that occurred in 2008 will be sustainable. Moody's anticipates that NPI will continue to generate CFO pre-WC to debt of approximately 15% or more and CFO pre-WC interest coverage of approximately 3.0x or more.

What Could Change the Rating - Up

NPI's long-term ratings could be positively impacted if NPI could demonstrate sustainable improvement in financial ratios, such as CFO pre-WC interest coverage above 4.0x and CFO pre-WC to debt in the high teens. This level of improvement in NPI's credit metrics could result from further rate increases, coupled with either an increase in equity in the capital structure or a higher equity risk premium utilized by the regulator to automatically adjust the allowed rate of return on rate base between full cost of capital hearings.

What Could Change the Rating - Down

Moody's considers a downward revision in NPI's rating to be unlikely in the near term. However, NPI's long-term ratings could be negatively impacted to the extent that Moody's perceived a reduction in the level of regulatory support combined with weaker liquidity and a sustained deterioration in NPI's credit metrics such as CFO pre-WC to interest coverage of less than 2.5x, CFO pre-WC to debt in the low teens and debt to capitalization in excess of 55%.

Newfoundland Power Inc.

Credit Metrics - OPEBS on Cash Basis

Pre-tax Interest Coverage (times)

Allowed Common Equity	Allowed Return On Equity											
	11.25%	**11.00%**	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**
45%	2.76	2.72	2.68	2.64	2.60	2.56	2.52	2.48	2.44	2.40	2.36	2.32
44%	2.71	2.68	2.64	2.60	2.56	2.52	2.48	2.44	2.40	2.37	2.33	2.29
43%	2.67	2.63	2.59	2.55	2.52	2.48	2.44	2.40	2.37	2.33	2.29	2.25
42%	2.62	2.58	2.55	2.51	2.47	2.44	2.40	2.36	2.33	2.29	2.25	2.22
41%	2.58	2.54	2.50	2.47	2.43	2.40	2.36	2.33	2.29	2.26	2.22	2.18
40%	2.53	2.50	2.46	2.43	2.39	2.36	2.32	2.29	2.25	2.22	2.18	2.15

Cash Flow Interest Coverage (times)

Allowed Common Equity	Allowed Return On Equity											
	11.25%	**11.00%**	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**
45%	3.42	3.40	3.37	3.34	3.32	3.29	3.26	3.24	3.21	3.18	3.16	3.13
44%	3.39	3.36	3.34	3.31	3.28	3.26	3.23	3.20	3.18	3.15	3.13	3.10
43%	3.35	3.33	3.30	3.28	3.25	3.22	3.20	3.17	3.15	3.12	3.10	3.07
42%	3.32	3.29	3.27	3.24	3.22	3.19	3.17	3.14	3.12	3.09	3.07	3.04
41%	3.28	3.26	3.23	3.21	3.18	3.16	3.14	3.11	3.09	3.06	3.04	3.02
40%	3.25	3.22	3.20	3.18	3.15	3.13	3.10	3.08	3.06	3.03	3.01	2.99

Cash Flow to Debt (percentage)

Allowed Common Equity	Allowed Return On Equity											
	11.25%	**11.00%**	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**
45%	18.4%	18.2%	18.0%	17.8%	17.6%	17.4%	17.2%	17.0%	16.8%	16.6%	16.4%	16.2%
44%	17.6%	17.4%	17.2%	17.0%	16.8%	16.6%	16.4%	16.2%	16.1%	15.9%	15.7%	15.5%
43%	16.8%	16.6%	16.4%	16.3%	16.1%	15.9%	15.7%	15.5%	15.4%	15.2%	15.0%	14.8%
42%	16.1%	15.9%	15.7%	15.6%	15.4%	15.2%	15.0%	14.9%	14.7%	14.5%	14.4%	14.2%
41%	15.4%	15.2%	15.1%	14.9%	14.7%	14.6%	14.4%	14.3%	14.1%	13.9%	13.8%	13.6%
40%	14.7%	14.6%	14.4%	14.3%	14.1%	14.0%	13.8%	13.7%	13.5%	13.4%	13.2%	13.1%

Newfoundland Power Inc.

Credit Metrics - OPEBS on Accrual Basis

Pre-tax Interest Coverage (times)

Allowed Common Equity	Allowed Return On Equity											
	11.25%	**11.00%**	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**
45%	2.77	2.73	2.69	2.65	2.61	2.57	2.53	2.49	2.45	2.41	2.37	2.33
44%	2.72	2.68	2.64	2.61	2.57	2.53	2.49	2.45	2.41	2.37	2.33	2.30
43%	2.68	2.64	2.60	2.56	2.52	2.49	2.45	2.41	2.37	2.34	2.30	2.26
42%	2.63	2.59	2.56	2.52	2.48	2.45	2.41	2.37	2.34	2.30	2.26	2.23
41%	2.58	2.55	2.51	2.48	2.44	2.41	2.37	2.33	2.30	2.26	2.23	2.19
40%	2.54	2.50	2.47	2.43	2.40	2.37	2.33	2.30	2.26	2.23	2.19	2.16

Cash Flow Interest Coverage (times)

Allowed Common Equity	Allowed Return On Equity											
	11.25%	**11.00%**	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**
45%	3.53	3.51	3.48	3.45	3.43	3.40	3.37	3.35	3.32	3.29	3.26	3.24
44%	3.50	3.47	3.44	3.42	3.39	3.37	3.34	3.31	3.29	3.26	3.24	3.21
43%	3.46	3.44	3.41	3.38	3.36	3.33	3.31	3.28	3.26	3.23	3.21	3.18
42%	3.42	3.40	3.37	3.35	3.33	3.30	3.28	3.25	3.23	3.20	3.18	3.15
41%	3.39	3.36	3.34	3.32	3.29	3.27	3.24	3.22	3.20	3.17	3.15	3.12
40%	3.35	3.33	3.31	3.28	3.26	3.24	3.21	3.19	3.17	3.14	3.12	3.10

Cash Flow to Debt (percentage)

Allowed Common Equity	Allowed Return On Equity											
	11.25%	**11.00%**	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**
45%	19.3%	19.1%	18.9%	18.7%	18.5%	18.3%	18.1%	17.9%	17.7%	17.5%	17.3%	17.1%
44%	18.4%	18.3%	18.1%	17.9%	17.7%	17.5%	17.3%	17.1%	16.9%	16.7%	16.5%	16.3%
43%	17.6%	17.5%	17.3%	17.1%	16.9%	16.7%	16.5%	16.4%	16.2%	16.0%	15.8%	15.6%
42%	16.9%	16.7%	16.5%	16.4%	16.2%	16.0%	15.8%	15.7%	15.5%	15.3%	15.2%	15.0%
41%	16.2%	16.0%	15.8%	15.7%	15.5%	15.4%	15.2%	15.0%	14.9%	14.7%	14.5%	14.4%
40%	15.5%	15.3%	15.2%	15.0%	14.9%	14.7%	14.6%	14.4%	14.3%	14.1%	14.0%	13.8%

Newfoundland Power Inc.

2010 Forecast Average Rate Base[1]
($000s)

	Forecast[2]
Plant Investment	754,952
Add:	
Deferred Charges	104,130
Weather Normalization Reserve	2,000
Deferred Energy Replacement Costs	192
Cost Recovery Deferral - Depreciation	3,257
Customer Finance Programs	1,750
	111,329
Deduct:	
2005 Unbilled Revenue	2,309
Accrued Pension Liabilities	3,502
Accrued OPEBS Liability	2,837
Municipal Tax Liability	683
Future Income Taxes	2,406
Purchased Power Unit Cost Reserve	224
Customer Security Deposits	643
	12,604
Average Rate Base Before Allowances	853,677
Cash Working Capital Allowance	9,266
Materials and Supplies Allowance	4,453
Average Rate Base At Year End	867,396

[1] All amounts shown are averages.
[2] Based upon proposed rates.

Newfoundland Power Inc.

2010 Revenue Requirements[1]
($000s)

		Existing	Changes	Proposed
1	**Return on Rate Base**	66,447	12,936	79,383
2				
3	**Other Costs**			
4	Power Supply Cost	355,737	(3,795)	351,942
5	Operating Costs	51,059	1,130	52,189
6	Pension	5,701	-	5,701
7	Additional OPEBs Expense[2]	-	5,930	5,930
8	Amortization of Depreciation Cost Recovery Deferral	3,861	-	3,861
9	Depreciation[3]	43,338	3	43,341
10	Income Taxes	13,132	8,035	21,167
11		472,828	11,303	484,131
12				
13	**2010 Revenue Requirement**	539,275	24,239	563,514
14				
15	**Deductions**			
16	Other Revenue	(13,800)	128	(13,672)
17	2005 Unbilled Revenue	(4,618)	-	(4,618)
18	Other Adjustments[4]	88	-	88
19		(18,330)	128	(18,202)
20				
21	Energy Supply Cost Variance Adjustments	(6,128)	6,128	-
22				
23	**2010 Revenue Requirement from Rates[5]**	514,817	30,495	545,312
24				
25	Forecast Operation of the Formula for 2010	(3,192)	3,192	-
26				
27	Forecast Revenue From Rates	511,625	33,687	545,312

1 See *Section 4.3, Forecast 2010 Revenue Requirements* for a summary of the Company's 2010 Revenue Requirements proposals.

2 $5,930,000 represents the increase in 2010 OPEB operating costs resulting from adoption of the accrual method of accounting, as included in the 2010 test year. This reflects $7,127,000 (the operating cost portion of $7,414,000 in OPEB costs on an accrual basis) minus $1,197,000 (the operating cost portion of $1,740,000 in OPEB costs on a cash basis).

3 Reflects impacts of recognition of OPEBs costs on an accrual basis.

4 Includes $38,000 related to the amortization of capital stock issue expenses and $50,000 related to customer security deposits.

5 Excludes price elasticity impacts related to revenue of $3,424,000. The required revenue increase in 2010 of $33,919,000 (See Exhibit 10, line 1, Column E) is comprised of $30,495,000 and price elasticity impacts of $3,424,000 (See Exhibit 10, line 1, Column D).

Newfoundland Power Inc.

2010 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	479,623	(7,191) [1]	472,429
4	Preference Shares	9,173	-	9,173
5	Common Equity	386,307	3,617 [2]	389,925
6		875,103	(3,574)	871,527
7				
8	**Average Capital Structure**			
9	Debt	54.81%	-0.60% [1]	54.21%
10	Preference Shares	1.05%	0.00%	1.05%
11	Common Equity	44.14%	0.60% [2]	44.74%
12		100.00%	0.00%	100.00%
13				
14	**Cost of Capital**			
15	Debt	7.62%	0.07% [1]	7.69%
16	Preference Shares	6.25%	0.00%	6.25%
17	Common Equity	6.87%	4.13% [2]	11.00%
18				
19	**Weighted Average Cost of Capital**			
20	Debt	4.18%	-0.01%	4.17%
21	Preference Shares	0.06%	0.00%	0.06%
22	Common Equity	3.03%	1.89%	4.92%
23		7.27%	1.88%	9.15%
24				
25	**Return on Rate Base**			
26	Return on Debt	36,123	(187) [1]	35,936
27	Return on Preference Shares	573	-	573
28	Return on Common Equity	29,751	13,123 [2]	42,874
29		66,447	12,936	79,383

[1] Reflects reduced borrowing requirements resulting from the proposed increase in cash revenue.
[2] Reflects the Company's proposed return on common equity of 11.0 percent in 2010.

Newfoundland Power Inc.

Pension Expense Variance Deferral Account

Proposed Definition

Pension Expense Variance Deferral Account

This account shall be charged or credited with the amount by which the annual pension expense computed in accordance with generally accepted accounting principles for any year differs from the annual pension expense approved in the latest test year for the establishment of revenue requirement from rates.

Disposition of any Balance in this Account
Newfoundland Power shall charge or credit any amount in this account to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

Newfoundland Power Inc.

2010 Average Rate Change[1]
($000s)

	Existing[2]	Proposed[3]	Difference	Price Elasticity[4]	Proposed Increase[5]
	A	B	C	D	E
Revenue From Rates	514,817	545,312	30,495	3,424	33,919
RSA Charges	40,882	40,589	(293)	293	-
MTA Charges	13,032	13,740	708	88	796
Total	568,731	599,641	30,910	3,805	34,715
Customer Rate Change[6]					6.1%

[1] The average rate change provides the estimated proposed change relative to customer rates in effect at time of filing the Application (i.e., effective July 1, 2008). The RSA and MTA billings included in the rate change calculation are the RSA and MTA Factors in effect at time of filing (i.e. effective July 1, 2008).

[2] 2010 Revenue from existing rates based on base rates effective July 1, 2008 .

[3] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from Exhibit 7. RSA and MTA billings based RSA and MTA Factors effective July 1, 2008.

[4] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.

[5] Difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C plus Column D).

[6] Total of Column E expressed as percentage of (Column A less Column D).

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Statements of Income
($000s)

		Existing	Proposed
1	Electricity Sales (GWh)	5,396	5,355
2			
3	Revenue From Rates	511,625	545,312
4	Amortization of 2005 Unbilled Revenue	4,618	4,618
5	Transfers from (to) the RSA	6,128	-
6		522,371	549,930
7			
8	Purchased Power Expense	353,726	349,931
9	Deferred Replacement Energy Costs	598	598
10	Amortization of Weather Normalization Reserve	2,101	2,101
11	Amortization of Purchased Power Unit Cost Variance Reserve	(688)	(688)
12		355,737	351,942
13			
14	Contribution	166,634	197,988
15			
16	Other Revenue	13,800	13,672
17			
18	Other Expenses:		
19	Operating Expenses[1]	52,774	53,903
20	Employee Future Benefit Costs	5,701	11,631
21	Amortization of Deferred Cost Recoveries	3,861	3,861
22	Depreciation	43,338	43,341
23	Finance Charges	36,211	36,024
24		141,885	148,760
25			
26	Income Before Income Taxes	38,549	62,900
27	Income Taxes	12,584	20,618
28			
29	Net Income	25,965	42,282
30	Preferred Dividends	573	573
31			
32	Earnings Applicable to Common Shares	25,392	41,709
33			
34			
35	**Rate of Return and Credit Metrics**		
36	Rate of Return on Rate Base (percentage)	7.27%	9.15%
37	Regulated Return on Book Equity (percentage)	6.87%	11.00%
38	Return on Book Equity (percentage)	6.57%	10.70%
39	Interest Coverage (times)	2.0	2.7
40	CFO Pre-W/C + Interest / Interest (times)	2.8	3.5
41	CFO Pre-W/C / Debt (percentage)	13.0%	18.9%

[1] Operating expenses shown are before the adjustment for non-regulated expenses.

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Statements of Retained Earnings
($000s)

		Existing	Proposed
1	Balance - Beginning	310,721	310,721
2	Net Income for the Period	25,965	42,282
3		336,686	353,003
4			
5	Dividends		
6	Preference Shares	573	573
7	Common Shares	14,861	23,943
8		15,434	24,516
9			
10	Balance - End of Period	321,252	328,487

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Balance Sheets
($000s)

	Existing	Proposed
Assets		
Current assets		
Accounts Receivable	$ 71,022	$ 73,685
Materials and Supplies	5,586	5,586
Prepaid Expenses	1,336	1,336
Regulatory Assets	6,077	3,624
	84,021	84,231
Capital assets	826,340	826,626
Deferred charges	101,022	100,643
Regulatory assets	197,558	188,205
Customer Finance Plans	1,750	1,750
	$ 1,210,691	$ 1,201,455
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued charges	$ 63,909	$ 63,471
Current Installments of long-term debt	5,200	5,200
Future Income Taxes	974	974
	70,083	69,645
Regulatory liabilites	80,778	80,778
Other liabilities	56,113	56,113
Long-term debt	484,301	469,912
Future Income Taxes	118,670	117,026
Shareholders' Equity		
Common shares	70,321	70,321
Preference shares	9,173	9,173
Retained earnings	321,252	328,487
	400,746	407,981
	$ 1,210,691	$ 1,201,455

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Statements of Cash Flows
($000s)

		Existing	Proposed
1	**Cash From (Used In) Operating Activities**		
2	Net Earnings	$ 25,965	$ 42,282
3			
4	**Items not affecting cash:**		
5	Amortization of capital assets	43,338	43,341
6	Amortization of deferred charges	225	225
7	Change in regulatory assets and liabilities	(4,715)	1,801
8	Future income taxes	357	(1,287)
9	Accrued employee future benefits	(1,459)	4,215
10	Change in non-cash working capital	(1,652)	(4,752)
11		62,059	85,825
12			
13	**Investing Activities**		
14	Capital expenditures (net of salvage)	(68,195)	(68,484)
15	Contributions from customers and security deposits	2,000	2,000
16		(66,195)	(66,484)
17			
18	**Financing Activities**		
19	Proceeds from long-term debt	24,770	10,375
20	Repayment of long-term debt	(5,200)	(5,200)
21	Dividends		
22	Preference Shares	(573)	(573)
23	Common Shares	(14,861)	(23,943)
		4,136	(19,341)
	Change in Cash	-	-
	Cash (Bank Indebtedness), Beginning of Year	-	-
	Cash (Bank Indebtedness), End of Year	$ -	$ -

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Average Rate Base[1]
($000s)

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

[1] All numbers shown are averages.

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Weighted Average Cost of Capital
($000s)

		Existing	Proposed
1	**Average Capitalization**		
2	Debt	479,623	472,429
3	Preference Shares	9,173	9,173
4	Common Equity	386,307	389,925
5		875,103	871,527
6	**Average Capital Structure**		
7	Debt	54.81%	54.21%
8	Preference Shares	1.05%	1.05%
9	Common Equity	44.14%	44.74%
10		100.00%	100.00%
11			
12			
13	**Cost of Capital**		
14	Debt	7.62%	7.69%
15	Preference Shares	6.25%	6.25%
16	Common Equity	6.87%	11.00%
17			
18			
19	**Weighted Average Cost of Capital**		
20	Debt	4.18%	4.17%
21	Preference Shares	0.06%	0.06%
22	Common Equity	3.03%	4.92%
23		7.27%	9.15%

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Rate of Return on Rate Base
($000s)

		Existing	Proposed
1	Regulated Return on Equity	26,559	42,874
2	Return on Preferred Equity	573	573
3		27,132	43,447
4			
5	Finance Charges		
6	Interest on Long-term Debt	35,849	35,849
7	Other Interest	461	305
8	Amortization of Bond Issue Expenses	187	187
9	AFUDC	(374)	(405)
10		36,123	35,936
11			
12	Return on Rate Base	63,255	79,383
13			
14	Average Rate Base	870,386	867,396
15			
16	Rate of Return on Rate Base	7.27%	9.15%

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Inputs and Assumptions

Energy Forecasts :	Energy forecasts are based on economic indicators taken from the Conference Board of Canada forecast, Provincial Outlook Spring 2009, Economic Forecast, dated April 21, 2009.
Revenue Forecast :	The revenue forecast is based on the Customer, Energy and Demand forecast dated May 2009
	Forecast revenues reflect the (i) amortization of the 2005 Unbilled Revenue, (ii) amortization of the municipa tax liability, (iii) the reclassification of interest on overdue accounts from finance charges, and (iv) recover through the RSA of amounts associated with the Supply Cost Variance Adjustment Clause for 2010 Existing
	Supply cost variances for 2010 Proposed are reflected in the 2010 Test Year Revenue Requirement
Purchased Power Expense :	Purchased Power expense reflects Hydro's Board approved rates and the Customer, Energy an Demand Forecast dated May, 2009.
	Purchased Power Expense for 2010 includes a Board approved $0.6 million per yea amortization related to the replacement energy costs associated with the Rattling Brook projec and $0.7 million per year amortization related to the disposition of the Purchased Power Uni Cost Variance Reserve.
	Purchased Power Expense for 2010 also includes a Board approved $2.1 million per yea amortization of the non-reversing balance in the Weather Normalization Reserve
Employee Future Benefit Costs :	Pension costs related to the 2005 Early Retirement Program are being amortized ove a 10-year period from 2005 to 2015 as approved in Order No. P.U. 49 (2004).
	Pension funding is based on the actuarial valuation dated December 31, 2008 filed with this Application.
	Pension expense discount rate is assumed to be 7.50% in 2010.
	Expected return on pension assets is assumed to be 7.0% for 2010.
	The 2010 forecast assumes that the accounting for OPEBs is on the Accrual Basis. The increase in 2010 employee future benefit expense due to the adoption of the accrual method is $5.9 million
	Pension funding is forecast based on the latest actuarial information and assumes special funding payments of $1.5 milllion in 2010.

Newfoundland Power Inc.

2010 Comparative Financial Forecasts
Inputs and Assumptions

Cost Recovery Deferral: In Order No. P.U. 39 (2006), the Board approved the deferred recovery of $5.8 million in 2007 costs related to the conclusion of the depreciation true up in 2005.

2010 costs include $3.9 million per year related to the amortization over a three-year period of cost recovery deferrals related to depreciation.

Depreciation Rates : Depreciation rates for 2010 are based on the 2006 depreciation study.

Depreciation costs for 2010 reflect a Board approved $0.2 million per year amortization of a $0.7 million depreciation true up resulting from the 2006 depreciation study.

Operating Costs : Operating forecasts for 2010 reflect the evidence filed in this Application

Deferred CDM costs of $1.5 million are being amortized on a straight-line basis over a 4-year period beginning in 2010.

Operating costs in 2010 also include $750,000 in external regulatory costs related to the 2010 general rate application.

Capital Expenditure : Capital Expenditures for 2010 reflect what is included in this Application.

Short-Term Interest Rates : Average short-term interest rates are assumed to be 2.0% for 2010.

Long-Term Debt : A $65.0 million long-term debt issue was completed on May 25, 2009. The debt is forecast for 30 years at a coupon rate of 6.606%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

Dividends : Common dividend payouts are forecast based on maintaining a target common equity component of 45%.

Income Tax : Income tax expense reflects a statutory income tax rate of 32% in 2010.

Effective July 1, 2008, the Board approved a reduction in customer rates of 0.18% to reflect the 2008 test year income tax true-up adjustment resulting form a reduction in federal tax rates for 2008.

Income tax expense for 2010 reflects the tax effecting of pension costs as approved by the Board in Order No. P.U. 32 (2007) and the tax effecting of OPEB costs.

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates[1]

	July 1, 2008 Existing Rates	January 1, 2010 Proposed Rates
Domestic - Rate #1.1		
Basic Customer Charge (B.C.C.)	$15.56/month	$15.56/month
Energy Charge - All kilowatt hours	9.631 ¢/kWh	10.370 ¢/kWh
Minimum Monthly Charge	$15.56/month	$15.56/month
Prompt Payment Discount	1.5% (min. $1)	1.5% (min. $1)
General Service 0-10 kW - Rate #2.1		
Basic Customer Charge (B.C.C.)	$17.85/month	$17.85/month
Energy Charge - All kilowatt hours	11.609¢/kWh	12.243¢/kWh
Minimum Monthly Charge		
- single phase	$17.85/month	$17.85/month
- three phase	$35.70/month	$35.70/month
Prompt Payment Discount	1.5% (min. $1)	1.5% (min. $1)
General Service 10-100 kW - Rate #2.2		
Basic Customer Charge (B.C.C.)	$20.55/month	$20.55/month
Demand Charge	$8.62/kW – winter	$8.62/kW – winter
	$7.12/kW – other	$7.12/kW – other
Energy Charge		
First 150 kWh/kW of billing demand	9.163 ¢/kWh	9.696 ¢/kWh
All Excess kWh	6.863 ¢/kWh	7.251 ¢/kWh
Maximum Monthly Charge	16.3 ¢/kWh + B.C.C.	17.3 ¢/kWh + B.C.C.
Minimum Monthly Charge	$20.55/month	$20.55/month
- three phase, not less than	$35.70/month	$35.70/month
Prompt Payment Discount	1.5% (min. $1)	1.5% (min. $1)

[1] Customer rates reflect Rate Stabilization & Municipal Tax Adjustments July 1, 2008.

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates

	July 1, 2008 Existing Rates	January 1, 2010 Proposed Rates
General Service 110-1000 kVA - Rate #2.3		
Basic Customer Charge (B.C.C.)	$92.53/month	$92.53/month
Demand Charge	$7.45/kVA-winter	$7.45/kVA-winter
	$5.95/kVA-other	$5.95/kVA-other
Energy Charge		
First 150 kWh/kVA of billing demand (max. 30,000 kWh)	9.032 ¢/kWh	9.634 ¢/kWh
All Excess kWh	6.714 ¢/kWh	7.147 ¢/kWh
Maximum Monthly Charge	16.3 ¢/kWh + B.C.C.	17.3 ¢/kWh + B.C.C.
Minimum Monthly Charge	$92.53/month	$92.53/month
Prompt Payment Discount	1.5% (max. $500)	1.5% (max. $500)
General Service 1000 kVA and Over - Rate #2.4		
Basic Customer Charge (B.C.C.)	$185.08/month	$185.08/month
Demand Charge	$7.04/kVA-winter	$7.04/kVA-winter
	$5.54/kVA-other	$5.54/kVA-other
Energy Charge		
First 100,000 kWh	7.649 ¢/kWh	8.209 ¢/kWh
All Excess kWh	6.589 ¢/kWh	7.063 ¢/kWh
Maximum Monthly Charge	16.3 ¢/kWh + B.C.C.	17.3 ¢/kWh + B.C.C.
Minimum Monthly Charge	$185.08/month	$185.08/month
Prompt Payment Discount	1.5% (max. $500)	1.5% (max. $500)

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates

			July 1, 2008 Existing Rates	January 1, 2010 Proposed Rates
Street and Area Lighting				
Sentinel/Standard Fixtures				
High Pressure Sodium	-	100W	$15.43	$16.35
	-	150W	$19.50	$21.00
	-	250W	$25.89	$28.46
	-	400W	$35.39	$39.55
Mercury Vapour	-	175W	$15.43	$16.35
	-	250W	$19.50	$21.00
	-	400W	$25.89	$28.46
Post Top Fixtures				
Mercury Vapour	-	175W	$16.24	$17.52
High Pressure Sodium	-	100W	$16.24	$17.52
Poles				
Wood			$6.27	$6.96
30' Concrete or Metal, direct buried			$9.26	$10.10
45' Concrete or Metal, direct buried			$14.67	$15.39
25' Concrete or Metal, Post Top, direct buried			$7.37	$7.79
Underground Wiring (per run)				
All sizes and types of fixtures			$12.35	$12.31