NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

May 10, 2007

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: 2007 General Rate Application

Forwarded with this letter are 10 copies of a general rate application for a full review of Newfoundland Power's 2008 costs (the "2008 General Rate Application").

The 2008 General Rate Application and prefiled supporting materials have been provided in three volumes set out as follows:

Volume 1: Application, Company Evidence and Exhibits

Volume 2: Supporting Materials

Volume 3: Expert Evidence

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 and, to that end, we would be pleased if the Board could indicate its requirements, if any, at its convenience.

The Company will post a copy of the 2008 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-Winsor, Gander, Clarenville, Burin, Carbonear, and St. John's.

Telephone: 709-737-5859 *Website: http://www.newfoundlandpower.com* *Fax: 709-737-5300*
palteen@newfoundlandpower.com

Attached to the formal Application as Schedule A are proposed rates. These rates are 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, 2007 contemporaneously with the filing of the 2008 General Rate Application. We would expect to update the 2008 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 2008 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 (6 copies)
Consumer Advocate

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B. COMPANY EVIDENCE

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2. Cash Working Capital Lead/Lag Study
3. Actuarial Valuation of Defined Benefit Pension Plan
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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 2008.

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. 32 (1968) and P.U. 1 (1974), the Board ordered the establishment of a Weather Normalization Reserve for Newfoundland Power.

4. 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").

5. By Order No. P.U. 19 (2003), the Board ordered Newfoundland Power, among other things, to:

   (a) submit a report with its next general rate application that addresses the use of the accrual method of accounting for other employee future benefits; and

   (b) adopt the asset rate base method for calculating its rate base.

6. By Order No. P.U. 40 (2005), the Board ordered Newfoundland Power to adopt the accrual method of revenue recognition commencing in 2006 which created the 2005 unbilled revenue.

7. By Order Nos. P.U. 40 (2005) and P.U. 39 (2006), the Board ordered, among other things, the deferred recovery, until further Order of the Board, of:

   (a) 2006 costs of $5,793,000; and

   (b) 2007 costs of $6,940,000.

8. By Order No. P.U. 10 (2007), the Board ordered that the Purchased Power Unit Cost Variance Reserve Account be considered at Newfoundland Power's next general rate application to be filed in 2007.

B. Newfoundland Power Proposals:

9. Newfoundland Power proposes that the Board approve the calculation of depreciation expense with effect from January 1, 2008 by:

   (a) use of the depreciation rates as recommended in the Depreciation Study filed with the Application; and

   (b) adjustment of depreciation expense to amortize over a four year period an accumulated reserve variance of approximately $700,000 identified in the Depreciation Study filed with the Application;

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

10. Newfoundland Power proposes that the Board approve, with effect from January 1, 2008:

   (a) the adoption of the accrual method of accounting for other employee future benefits; and

   (b) the adoption of the accrual method of accounting for income tax related to all employee future benefits;

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

11. Newfoundland Power proposes that the Board approve the continued use of the Formula with changes to:

   (a) use an equity risk premium of 5.25 percent at a risk free rate of 5 percent for 2008;

(b) revise the method for determining the risk free rate for the period subsequent to 2008; and

(c) reflect the adoption of the asset rate base method;

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

12. Newfoundland Power proposes that the Board approve amortizations with effect from January 1, 2008 to:

(a) amortize as revenue over a five year period:

(i) $16,446,000 of 2005 unbilled revenue; and

(ii) $4,087,000 related to a timing difference in receipt and recognition of municipal taxes;

(b) amortize the recovery over a five year period of $12,733,000 in costs described in paragraph 7 of this Application;

(c) amortize the recovery over a five year period of $6,800,000 of the balance in the Weather Normalization Reserve;

(d) amortize over a five year period the balance of $1,342,000 in the Purchased Power Unit Cost Variance Reserve Account; and

(e) amortize the recovery over a three year period of an estimated $1,250,000 in Board and Consumer Advocate costs related to the Application;

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

13. Newfoundland Power proposes, with effect from January 1, 2008, that the Board:

(a) discontinue the Purchased Power Unit Cost Variance Reserve Account; and

(b) approve a Demand Management Incentive Account;

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

14. Newfoundland Power proposes that the Board approve an overall average increase in customer rates of 5.3 percent with effect from January 1, 2008, based upon:

(a) a forecast average rate base for 2008 of $809,291,000 calculated in accordance with the asset rate base method;

(b) a rate of return on average rate base for 2008 of 8.82 percent in a range of 8.64 percent to 9 percent; and

(c) a forecast revenue requirement for 2008 of $502,486,000 to be recovered from electrical rates, following implementation of the proposals set out in the Application;

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

15. Newfoundland Power proposes that the Board approve rates, tolls and charges effective for service provided on and after January 1, 2008, which result in average increases in customer rates by class as follows:

Rate Class	***Average Increase***
Domestic	6.4%
General Service 0-10kW	1.3%
General Service 10-100 kW (110 kVA)	2.3%
General Service 110-1000 kVA	4.3%
General Service 1000 kVA and Over	5.3%
Street and Area Lighting	5.3%

as set out in Schedule A to the Application.

16. Newfoundland Power proposes that the Board approve amendments to the rules and regulations governing Newfoundland Power's provision of electrical service to its customers to, in effect:

(a) provide for reasonable recovery of energy supply costs through the Rate Stabilization Account;

(b) eliminate the requirement for payment in advance of fees for temporary connections, special facilities and relocations; and

(c) allow a fee of $16 for each rejected payment;

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

C. Order Requested:

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

(a) pursuant to Section 68 of the Act, the calculation of depreciation expense as set out in paragraph 9 of the Application;

(b) pursuant to Section 58 of the Act, the adoption of (i) the accrual method of accounting for other employee future benefits and (ii) the accrual method of accounting for income tax related to all employee future benefits, as set out in paragraph 10 of the Application;

(c) pursuant to Section 80 of the Act, changes to, and continued use beyond 2008 of, the Formula as set out in paragraph 11 of the Application;

(d) pursuant to Section 58, 69 and 80 of the Act, the amortizations set out in paragraph 12 of the Application;

(e) pursuant to Section 58 and 80 of the Act, the Demand Management Incentive Account as set out in paragraph 13 of the Application;

(f) pursuant to Sections 70 and 80 of the Act, rates, tolls and charges as set out in paragraphs 14 and 15 of the Application subject to modification for any intervening Order of the Board affecting rates, tolls and charges;

(g) pursuant to Section 71 and 80 of the Act, amendments to the rules and regulations governing Newfoundland Power's provision of service to its customers to effect the changes set out in paragraph 16 of the Application; and

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

D. Communications:

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

DATED at St. John's, Newfoundland, this 10th day of May, 2007.

NEWFOUNDLAND POWER INC.

Ian F. Kelly, Q.C. and Gerard Hayes
Newfoundland Power Inc.
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55 Kenmount Road
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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 2008.

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 10th day of May, 2007,
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 10, 2007)

Basic Customer Charge: .... $15.59 per month

Energy Charge:
All kilowatt-hours .... @ 9.586¢ per kWh

Minimum Monthly Charge .... $15.59 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 10, 2007)

Basic Customer Charge: .... $19.08 per month

Energy Charge:
All kilowatt-hours .... @ 11.462 ¢ per kWh

Minimum Monthly Charge, Single Phase .... $19.08 per month
Three Phase .... $38.16 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 10, 2007)

Basic Customer Charge: .... $20.60 per month

Demand Charge:
$8.63 per kW of billing demand in the months of December, January, February and March and $7.13 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 .... @ 9.108 ¢ per kWh
All excess kilowatt-hours .... @ 6.799 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.8 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

Single Phase .... $20.60 per month
Three Phase .... $38.16 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 10, 2007)

Basic Customer Charge: .... $92.73 per month

Demand Charge:
$7.46 per kVA of billing demand in the months of December, January, February and March and $5.96 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 .... @ 8.886 ¢ per kWh
All excess kilowatt-hours .... @ 6.645 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.8 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 10, 2007)

Basic Customer Charge: .... $185.46 per month

Demand Charge:
$7.05 per kVA of billing demand in the months of December, January, February and March and $5.55 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 .... @ 7.403 ¢ per kWh
All excess kilowatt-hours .... @ 6.501 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.8 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 10, 2007)

	Sentinel/Standard	Post Top
High Pressure Sodium*		
100W (8,600 lumens)	$15.56	$16.42
150W (14,400 lumens)	19.45	-
250W (23,200 lumens)	25.60	-
400W (45,000 lumens)	34.80	-

* For all new installations and replacements.

Mercury Vapour		
175W (7,000 lumens)	$15.56	$16.42
250W (9,400 lumens)	19.45	-
400W (17,200 lumens)	25.60	-

Special poles used exclusively for lighting service**	
Wood	$ 6.76
30' Concrete or Metal, direct buried	9.91
45' Concrete or Metal, direct buried	15.72
25' Concrete or Metal, Post Top, direct buried	7.88
Underground Wiring (per run)**	
All sizes and types of fixtures	$13.20

** 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 OVERVIEW

Newfoundland Power ("the Company") is principally an electricity delivery and customer service organization. Newfoundland Power's electricity system is mature. The electricity system serves a relatively low-growth market.

Table 1 shows the number of customers served by Newfoundland Power and the annual weather adjusted sales of Newfoundland Power for the period 2002 to 2008F.[1]

Table 1
Customers and Sales: 2002 to 2008F

	2002	2003	2004	2005	2006	2007F	2008F
Number of Customers	219,072	221,653	224,464	227,301	229,500	231,715	233,714
Annual Sales (GWh)	4,765	4,882	4,979	5,004	4,995	5,054	5,121

From 2002 through 2008, the number of customers served by Newfoundland Power is increasing by an average of 1.1 percent per year. The annual weather adjusted sales are increasing by an average of 1.2 percent per year over this period.

Newfoundland Power's outlook for growth in the number of customers and sales reflects both recent trends and longer term demographics.

Newfoundland Power's primary source of electricity supply is Newfoundland and Labrador Hydro ("Hydro") which generates approximately 90 percent of the electricity delivered by Newfoundland Power to its customers.

[1] References to years with the notation 'F' (i.e. 2008F), are intended to indicate *forecast*.

1.2 PERFORMANCE

1.2.1 Customer Operations Performance

Newfoundland Power continues to deliver safe, reliable service in a cost effective manner. Since 2002, both the reliability and quality of service has improved.

Table 2 shows the contribution of Newfoundland Power's costs to the total cost of electricity on a kWh basis for the period 2002 to 2006.

Table 2
Cost of Electricity: 2002 to 2006
(cents/kWh)

	2002	2003	2004	2005	2006
Total Cost of Electricity[2]	7.97	8.12	8.60	9.19	9.63
Newfoundland Power's Contribution[3]	3.19	3.07	3.08	3.07	3.05

The contribution of Newfoundland Power's costs to the cost of the electricity provided to customers has remained stable through this period.

The Company's customer operations are well managed. 2008 operating costs are not forecast to increase from 2003 levels.

Improved service and cost control are the foundation of customer operations performance of Newfoundland Power.

[2] Cost of electricity divided by electricity sales. Cost of electricity includes rate stabilization account ("RSA") charges, municipal tax account ("MTA") charges and the Company's revenue from rates.

[3] The contribution margin divided by electricity sales. The contribution margin is the Company's revenue from rates less purchased power expense.

Section 2: Customer Operations provides greater detail on the service Newfoundland Power delivers to its customers and the forecast cost of delivery of that service.

1.2.2 Financial Performance

Since 2002, Newfoundland Power has earned a rate of return on rate base that is within the ranges approved by the Board, although since 2005 the rate of return has been close to the lower end of the approved ranges.[4]

Table 3 compares Newfoundland Power's earned rates of return on rate base to the midpoint of the range approved by the Board for ratemaking purposes for the period 2002 to 2006.

Table 3
Rate of Return on Rate Base: 2002 to 2006
(percent)

	2002	**2003**	**2004**	**2005**	**2006**
Approved Midpoint	10.06	8.96	8.91	8.68	8.68
Actual Return	9.94	9.03	8.82	8.53	8.57

Since Newfoundland Power's last general rate application in 2003, its earned returns on equity have been reflective of those used by the Board for ratemaking purposes. However, credit metrics have deteriorated through the period. Part of the erosion of credit metrics is attributable to the reduction in ratemaking rates of return on common equity through the period and part is attributable to reduced recovery of depreciation costs.

Section 3: Finance provides greater detail on the past and prospective financial performance of Newfoundland Power.

[4] The *range* of return on rate base is ± 18 basis points or ± 0.18 percent.

1.3 ELECTRICITY PRICE

The price of electricity has increased substantially since 2002. The principal driver of electricity price increases in the 5 years ending in 2006 has been the price of No. 6 fuel burned at Hydro's Holyrood thermal generating station ("Holyrood"). In 2002, the average price of fuel burned at Holyrood was approximately $30 per barrel. By 2006, the price had increased by over 60 percent to $50 per barrel.

Since 2002, customer rates have increased by over 26 percent.[5]

Table 4 shows electricity price changes for Newfoundland Power customers in the period 2002 to April 2007.

Table 4
Rate Changes: 2002 to 2007
(percent)

	2002	2003	2004	2005	2006	2007	Total[6]
Newfoundland Power[7]	-0.6	-0.2	-	-0.5	-	-0.5	-1.8
Newfoundland Hydro[8]	3.7	-	5.3	-	-	3.1	12.6
RSP/RSA/MTA[9]	-0.1	2.0	4.5	5.2	4.8	-2.5	14.5

[5] On a compounded basis.

[6] The total reflects the *compounded* change in rates from 2002 to 2007.

[7] Rate changes for 2002, 2005 and 2007 were the result of the operation of the automatic adjustment formula which sets Newfoundland Power's annual return on rate base. The rate change for 2003 resulted from Order No. P.U. 19 (2003).

[8] These rate changes resulted from Orders on Hydro general rate applications and include the effects of rebasing fuel costs from the RSP/RSA fuel rider into Hydro base rates (see Order Nos. P.U. 9 (2002-2003), P.U. 19 (2004) Amended and P.U. 8 (2007)).

[9] These rate changes result from operation of Hydro's rate stabilization plan ("RSP") and Newfoundland Power's RSA which principally operate to ensure timely recovery of the cost of Holyrood fuel. For 2003, 2005 and 2006, the rate changes reflected changes in fuel costs or fuel forecasts in accordance with the Board's Orders. For 2004, the rate change reflects the recovery of Hydro's pre-2004 legacy Holyrood fuel costs of approximately $115 million (see Order No. P.U. 19 (2004) Amended). For 2007, the rate change was the result of a one-time adjustment to reflect reduced Holyrood fuel usage caused by higher hydroelectric production (see Order No. P.U. 8 (2007)) but does not reflect an expected 2.9 percent rate reduction on July 1, 2007 as a result of the operation of RSP/RSA. Adjustments associated with the MTA have a minimal impact on rate changes over the 2002 to 2007 period.

Electricity prices are expected to continue to be highly influenced by the cost of fuel burned at Holyrood.

As of 2007, marginal wholesale supply costs for Newfoundland Power will meet or exceed the revenue Newfoundland Power can expect to receive for those sales. This reflects the relatively high cost of Holyrood fuel and changes in the wholesale rate design. This development, where Newfoundland Power's costs exceed revenues on a marginal basis, can be expected to impact the regulation of the Company.

1.4 REGULATION

Newfoundland Power is regulated under the provisions of the *Public Utilities Act* (the "Act") and the *Electrical Power Control Act, 1994* (the "EPCA"). The Board's statutory power and responsibilities under the Act and the EPCA are required to be discharged in a transparent manner consistent with generally accepted sound public utility practice.

Prior to this Application, Newfoundland Power last filed general rate applications with the Board in 1998 and 2002. These filing intervals have been reflective of both the stability in Newfoundland Power's overall cost structure and the Board's use of regulatory mechanisms such as the automatic adjustment formula to set Newfoundland Power's annual return on rate base.

The stability in Newfoundland Power's overall cost structure has been the result of purposeful management of the balance between customer expectations and the cost of the Company's reasonable fulfillment of those expectations. The Board's use of regulatory mechanisms has complemented Newfoundland Power's cost stability and provided for transparent least cost regulation in the circumstances that presented themselves over the past decade.

The variability of the price of fuel burned at Holyrood is expected to continue to be a primary near-term determinant of the price customers will pay for electricity. Over the longer term, supply costs can be expected to exert a generally upward pressure on price. This simply reflects the economic reality that future generation costs are expected to exceed embedded generation costs. These dynamics are, in varying degrees, affecting electricity customers throughout Canada.

Supply cost dynamics in which wholesale supply costs exceed revenue on a marginal basis, can be expected to potentially affect regulation of Newfoundland Power in at least two ways. First, the interval between general rate applications could be reduced. Under the current wholesale supply rate, even modest growth in customer load will reduce the amount of contribution available to cover Newfoundland Power's costs other than supply costs. This, in turn, may require Newfoundland Power to file more frequent general rate applications than over the past decade simply to recover the cost associated with supplying modest customer growth. Second, the high price of fuel can be expected to increase the regulatory focus on customer rate design and, in particular, the economic efficiency of customer rate design. This increased focus can be expected to occupy more of the regulatory agenda in the near term than it has in the recent past.

In this Application, Newfoundland Power has proposed changes to regulatory mechanisms which will permit continued transparent least cost regulation in the context of current supply cost dynamics.

Recent developments of a process nature are expected to impact the regulation of Newfoundland Power. In 2006, Hydro's general rate application was substantially resolved by means of a series of negotiated agreements between Hydro and its stakeholders. The advent of more negotiated and mediative processes to resolve regulatory issues in this province is consistent with regulatory development across Canada. Reasonable resolution of issues through such processes can deliver tangible benefits to customers by lowering overall regulatory costs.

1.5 APPLICATION OVERVIEW

1.5.1 2008 Revenue Requirements

In this Application, Newfoundland Power is requesting an average increase in current customer rates of approximately 5.3 percent in 2008. This increase results from three primary changes in Newfoundland Power's costs.

Depreciation cost recovery accounts for an approximate 1.9 percent increase in 2008 revenues. This increase is principally due to the 2005 conclusion of the reserve variance true-up.

In order to sustain creditworthiness and financial integrity, the Company is targeting a 2008 return on equity of 10.25 percent. The 2007 return on equity for ratemaking purposes is 8.60

percent. An approximate 1.9 percent revenue increase in 2008 is attributable to improving the Company's 2008 return on rate base to reflect a return on common equity of 10.25 percent.

The Board has directed the Company to file a report with this Application to address the use of the accrual method for recognizing other employee future benefits. The Company has completed this review and proposes to recognize other employee future benefits on an accrual basis commencing in 2008. Implementing the Company's proposals related to employee future benefits accounts for an approximate 1.5 percent increase in 2008 revenue.

In addition to these three costs, other proposals made in this Application, such as those relating to the amortization of revenue and cost deferrals and outstanding reserve balances, also affect 2008 revenue requirements.

1.5.2 Other Proposals

To ensure the continued fairness of electricity pricing, the Company is proposing to vary rate increases by customer class. For Domestic customers, this will result in an increase of approximately 1 percent higher than average. For General Service customers, this will result in increases which will be generally lower than average.

This Application includes proposals relating to existing regulatory mechanisms. Newfoundland Power has proposed a continuation of a demand management incentive substantially in its current form.[10] Changes to the RSA are proposed to permit the Company to recover the fuel

[10] The existing Purchased Power Unit Cost Variance Reserve provides an incentive to minimize customers' peak demand.

related costs associated with customer growth on an ongoing basis. Changes to the automatic adjustment formula are proposed to reflect changes in rate base calculation, estimation of a risk free rate and Newfoundland Power's proposal for 2008 return on equity.

Finally, the evidence filed in support of this Application is consistent with the Board's directions regarding calculation of Newfoundland Power's rate base. It also outlines the Company's response to Board directions regarding inter-corporate relationships.

SECTION 2: CUSTOMER OPERATIONS

2.1 OVERVIEW

Newfoundland Power's customers expect the Company to deliver reliable electrical service at the least cost reasonable. Responsiveness to this customer expectation is central to Newfoundland Power's management of customer operations.

Managing customer service delivery at least cost necessarily requires balance. The fulfilment of customer's expectations has cost consequences. So cost does provide a degree of constraint in service delivery.

Customer satisfaction regarding Newfoundland Power's customer service delivery has averaged 89 percent since 2002.

Forecast 2008 operating costs represent approximately 10 percent of the Company's forecast 2008 cost of service. Newfoundland Power's forecast 2008 operating costs are less than those of a decade earlier.[1] Over this same period, electrical service reliability has materially improved.[2]

Newfoundland Power's service obligation has two distinct aspects. The first aspect relates to service reliability and is focused on the continuous provision of electricity supply. This aspect has a high degree of engineering orientation. The second aspect relates to the interaction between the Company and its customers.

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1 Newfoundland Power's 1998 operating costs were $51.5 million. Its forecast 2008 operating costs are $49.6 million.

2 In 1998, the average *number* of power interruptions per customer was 5.60, while the average *hours* of power interruption per customer was 7.41. This is compared to 2.90 and 2.98 respectively in 2006.

This section of Newfoundland Power's evidence reviews customer operations costs and service levels since 2002[3] and includes the Company's forecast 2008 operating and capital costs.

2.2 COST EFFICIENCY

For the purposes of establishing 2008 customer rates, the Board must consider Newfoundland Power's forecast 2008 operating and capital costs.

Forecast 2008 operating costs are virtually unchanged from actual 2003 operating costs and are consistent with efficient management and the least cost delivery of reliable service to customers.

Forecast 2008 capital expenditures are lower than Newfoundland Power's actual annual capital expenditures in recent years.

This section of the Customer Operations evidence provides an overview of operating costs since 2002 as well as details on forecast 2008 operating and capital costs.

2.2.1 Introduction

Operating costs are those costs over which Newfoundland Power has the greatest degree of management control. Operating costs represent approximately 10 percent of the Company's forecast 2008 revenue requirement.[4]

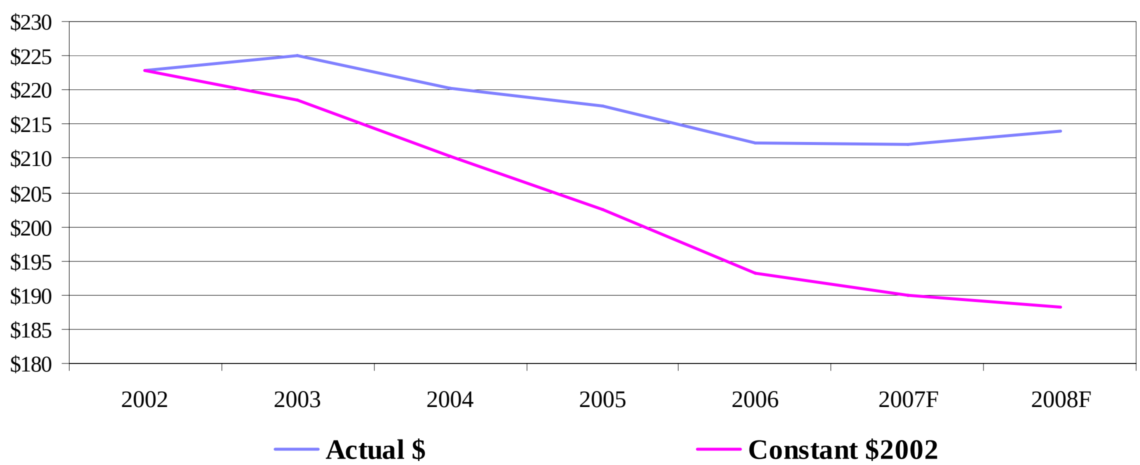
[3] The Company submitted its last general rate application to the Board in October 2002.
[4] Exhibit 9 contains the proposed revenue requirement for 2008.

Newfoundland Power's overall operating costs, excluding pension and deferred regulatory costs,[5] have been stable since 2002. Test year 2008 operating costs of $49.6 million are virtually the same as 2003 operating costs.

From 2002 through 2008, inflation, as measured by the provincial Consumer Price Index, is expected to be over 13 percent. In the same period, the number of customers served by Newfoundland Power is expected to increase by over 6 percent.

Graph 1 shows the operating costs per customer for 2002 to 2008F on an actual dollar basis and constant 2002 dollar basis.[6]

Graph 1
Operating Costs Per Customer
2002 to 2008F



Since 2002, operating costs per customer have decreased on both an actual and constant dollar basis. Newfoundland Power's operating costs associated with serving a customer have

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[5] Pension and deferred regulatory costs are reviewed in *Sections 3.2.3 Pension Costs and 3.7.3 Application Costs* respectively. References to *operating costs* in this *Section 2: Customer Operations* do not include pension and deferred regulatory costs.

[6] Constant 2002 dollars adjust for the impact of inflation since 2002.

decreased by approximately $34, or 15 percent, from 2002 to 2008F on an inflation adjusted basis and approximately $9, or 4 percent, on an actual dollar basis.

2.2.2 Operating Costs

General

Table 5 shows operating costs from 2002 actual to 2008F.

Table 5
Operating Costs[7]
2002 to 2008F
($000s)

	2002	2003	2004	2005	2006	2007F	2008F
Operating Costs	48,804	49,506	49,102	49,111	48,691	49,099	49,573

Total operating costs have remained stable at approximately $49 million from 2002 to 2006 and are forecast to remain so through 2008.

An understanding of Newfoundland Power's operating costs can be had 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 contain operating costs by function and by breakdown respectively from 2002 to 2008F.

7 Excludes pension and deferred regulatory costs.

By Function

Table 6 summarizes operating costs by 3 categories: Electricity Supply, Customer Service and General for 2002 to 2008F.[8]

Table 6
Operating Costs by Category
2002 to 2008F
($000s)

Category	**2002**	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Electricity Supply	22,376	21,109	22,071	21,453	21,194	21,137	21,480
Customer Service	8,928	9,519	9,561	10,136	10,034	10,020	10,144
General	17,500	18,878	17,470	17,522	17,463	17,942	17,949
Total	**48,804**	**49,506**	**49,102**	**49,111**	**48,691**	**49,099**	**49,573**

While fluctuations in operating costs occur yearly between categories, overall operating costs have remained essentially flat.

Table 7 shows the operating costs associated with the Electricity Supply category broken out by function for 2002 to 2008F.

Table 7
Operating Costs – Electricity Supply
2002 to 2008F
($000s)

Function	**2002**	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Distribution	5,944	5,677	6,227	6,388	6,721	6,499	6,574
Transmission	597	645	814	490	486	661	750
Substations	2,265	2,550	2,939	2,442	2,530	2,494	2,495
Power Produced	2,174	2,383	2,822	2,646	2,688	2,511	2,516
Administration & Engineering	7,833	6,518	6,723	5,926	5,315	5,466	5,580
Telecommunications	848	789	616	1,603	1,467	1,514	1,525
Environment	1,148	769	583	462	496	510	545
Fleet Operations & Maintenance	1,567	1,778	1,347	1,496	1,491	1,482	1,495
Electricity Supply	**22,376**	**21,109**	**22,071**	**21,453**	**21,194**	**21,137**	**21,480**

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

Total operating costs forecast for Electricity Supply in test year 2008 are less than actual costs incurred in 2002.

Electricity supply costs have decreased in the Administration & Engineering, Environment and Fleet Operations & Maintenance functions. Administration & Engineering reductions are principally the result of organizational change and technology deployment which has decreased supervisory and clerical labour costs. Cost reductions in the Environment function are the result of improved environmental performance, particularly a reduction in the number of oil spills from distribution transformers. Fleet Operations & Maintenance costs have decreased, despite rising fuel costs, principally due to a reduction in the number of vehicles by 35 units since 2002.

Electricity supply costs have increased in Distribution, Transmission, Substations, Power Produced and Telecommunications. These increases reflect the Company's allocation of resources to preventive maintenance programs associated with the core power system assets.[9] Operating costs associated with the Telecommunications function have increased principally as a result of the centralization of telecommunications costs under one function. Prior to 2005, telecommunications costs were allotted over several functions.

[9] These programs are reviewed in *Section 2.3.2 Reliability*.

Table 8 shows costs associated with the Customer Service category broken out by function for 2002 to 2008F.

Table 8
Operating Costs – Customer Service
2002 to 2008F
($000s)

Function	**2002**	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Customer Services	8,228	8,411	8,598	8,978	9,073	9,020	9,094
Uncollectible Bills	700	1,108	963	1,158	961	1,000	1,050
Customer Service	**8,928**	**9,519**	**9,561**	**10,136**	**10,034**	**10,020**	**10,144**

Operating costs in Customer Service have increased by approximately 12 percent since 2002. This reflects, in part, an increase in calls received at the Customer Contact Centre of over 13 percent in this period. In addition, there have been increases in the cost of meter reading and postage. The number of meter readings has increased by approximately 5 percent as a result of increases in customer accounts.[10] Postage costs have increased by 22 percent from 2002 to 2006.[11] The Company mails approximately 12,000 items each business day.

[10] Meter readings have increased by 126,000 since 2002.

[11] Postage costs have increased from $1,051,339 in 2002 to $1,286,010 in 2006. The $234,671 increase in costs is the result of an increase in the number of customer accounts and an approximately 17 percent increase in postal rates.

Table 9 shows the costs associated with the General category broken out by function for 2002 to 2008F.

Table 9
Operating Cost – General
2002 to 2008F
($000s)

Function	**2002**	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Information Systems	2,787	2,663	2,773	2,698	2,685	2,766	2,826
Financial Services	1,439	1,290	1,350	1,426	1,527	1,346	1,376
Corporate & Employee Services	12,176	13,536	11,837	11,745	11,557	12,102	11,972
Insurances	1,098	1,389	1,510	1,653	1,694	1,728	1,775
General	**17,500**	**18,878**	**17,470**	**17,522**	**17,463**	**17,942**	**17,949**

Test year 2008 costs in the General category are consistent with actual costs incurred from 2002 to 2006. Cost reduction in the Financial Services and Corporate & Employee Services functions has been offset by increased cost in insurances. Newfoundland Power's insurances cost increased by 54 percent from 2002 to 2006 during a period of generally increasing insurance premiums throughout much of the industry as a result of acts of terrorism and natural disasters.

By Breakdown

The primary breakdowns of Newfoundland Power's operating costs are by Labour and Other.

Table 10 provides the breakdown of operating costs for 2002 to 2008F.

Table 10
Operating Cost by Breakdown
2002 to 2008F
($000s)

Breakdown	**2002**	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Labour	28,410	27,156	28,454	28,300	28,136	28,200	28,671
Other	20,394	22,350	20,649	20,811	20,555	20,899	20,902
Total	**48,804**	**49,506**	**49,102**	**49,111**	**48,691**	**49,099**	**49,573**

Labour is the largest component of Newfoundland Power's operating costs, representing approximately 58 percent of total operating costs.

During 2002 to 2006, total operating labour decreased by 1 percent, while Other increased by 0.8 percent. Overall operating costs are forecast to increase by 1.8 percent in the 2008 test year over actual 2006 costs. The cost increase includes annual salary increases negotiated with unionized employees in two separate five-year collective agreements.[12]

Table 11 provides the breakdown of Labour costs for 2002 to 2008F.

Table 11
Labour Cost by Breakdown
2002 to 2008F
($000s)

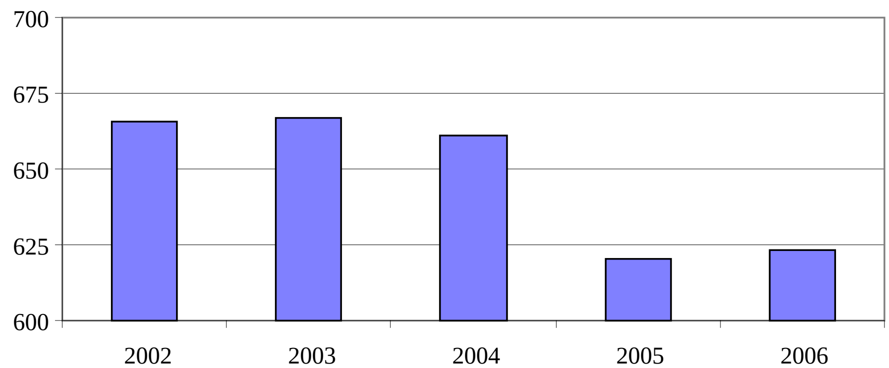
Breakdown	**2002**	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Regular and Standby	24,962	23,674	24,689	24,568	24,463	24,642	25,188
Temporary	1,545	1,723	2,097	2,232	2,204	2,127	2,040
Overtime	1,903	1,759	1,668	1,500	1,469	1,431	1,443
Total Labour	**28,410**	**27,156**	**28,454**	**28,300**	**28,136**	**28,200**	**28,671**

Regular labour costs decreased by 2 percent from 2002 to 2006. The use of seasonal temporary labour has offset increases in regular labour cost that would have otherwise occurred. Overtime costs are lower primarily because better system reliability has resulted in fewer power outages that must be responded to after regular working hours.

[12] Bargaining unit salaries are forecast to increase by 4 percent in 2008. However, labour is forecast to increase by approximately 2 percent in 2008. As in the past, 2008 salary increases are forecast to be substantially offset by productivity improvement.

Graph 2 shows Newfoundland Power's total workforce, measured in full time equivalents ("FTEs"), for 2002 to 2006.

Graph 2
Full Time Equivalents
2002 to 2006



Since 2002, the Company has reduced its workforce by approximately 6 percent[13] while the number of customers increased by approximately 5 percent.[14] The workforce reduction was principally the result of an Early Retirement Program ("ERP") offered in the first quarter of 2005.[15]

Exhibit 3 is a net present value analysis of the 2005 ERP.

The 2005 ERP has a positive net present value of approximately $14 million through 2015.

Over the past decade or so, productivity measures created opportunities to reduce labour cost from what it otherwise would have been through workforce reductions using ERPs.[16] ERPs have

[13] FTEs reduced from 666 in 2002 to 623 in 2006.
[14] Customers increased from 219,072 in 2002 to 229,500 in 2006.
[15] The workforce reduction was also affected by management decisions such as the 2005 outsourcing of cash services to Dominion stores.
[16] Workforce reductions through ERPs without a related reduction in service levels can only be achieved through increased productivity.

enabled Newfoundland Power to effectively keep its labour costs flat, while improving service to its customers.

The extent to which Newfoundland Power can use ERPs to reduce labour beyond 2008 may be limited by labour market factors such as Newfoundland Power's workforce demographics[17] and competitive job alternatives, including those outside the province.[18]

2.2.3 Capital Forecast

Newfoundland Power's annual capital budgets reflect the large number of assets spread over a broad geographic area that make up the electrical system.[19] Annual capital budgets are principally aimed at the refurbishment of existing capital assets and the extension of the electricity network to meet customer service requirements.

For ratemaking purposes, a capital forecast for the 2008 test year must be considered and approved by the Board.[20]

[17] In 5 years, 10 percent of employees in the core utility occupations at Newfoundland Power including linepersons, industrial electricians and millwrights, technologists and engineers, will be eligible for retirement. In 10 years, this will increase to 40 percent.

[18] Newfoundland Power responds to competitive market forces of this nature by recruiting at competitive rates.

[19] Electrical assets include 23 hydroelectric plants; 6 thermal plants; 130 substations with almost 4,000 pieces of critical electrical equipment; approximately 270,000 distribution poles; 27,000 transmission poles; and approximately 10,000 km of distribution and transmission circuitry.

[20] Newfoundland Power's 2008 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 12 shows capital expenditures for 2002 to 2008F.

Table 12
Capital Expenditures
2002 to 2008F
($000s)

Function	**2002**	**2003**	**2004**	**2005**	**2006**	**2007B**[21]	**2008F**
Generation	7,520	8,717	8,468	4,578	5,017	19,188[22]	5,585
Substations	5,986	7,418	5,598	4,076	4,435	3,968	5,276
Transmission	3,089	4,091	2,061	2,651	4,456	4,283	4,890
Distribution	30,966	30,459	30,762	31,076	33,375	24,103	26,636
General Property	715	1,102	906	1,126	2,244	1,995	977
Transportation	1,609	3,429	2,660	2,838	2,751	2,206	2,214
Telecommunications	343	253	177	102	173	101	224
Information Systems	5,074	6,197	3,968	3,408	3,430	3,457	3,502
Unforeseen Allowance	-	-	-	-	-	750	750
GEC	2,868	2,648	3,161	3,125	2,748	2,800	2,800
Total	**58,170**	**64,314**	**57,761**	**52,980**	**58,629**	**62,851**	**52,854**

The 2008 capital forecast is broadly consistent on a functional basis with expenditures since 2002.

2.3 SERVING CUSTOMERS

The reliability of the electrical service Newfoundland Power provides its customers has materially improved since 2002.

Newfoundland Power is responsive to customers' expectations. Those expectations have resulted in increased volume and diversity in customers' interactions with the Company, including an increased focus on energy efficiency.

This section of the Customer Operations evidence provides an overview of system reliability and customer relations since 2002.

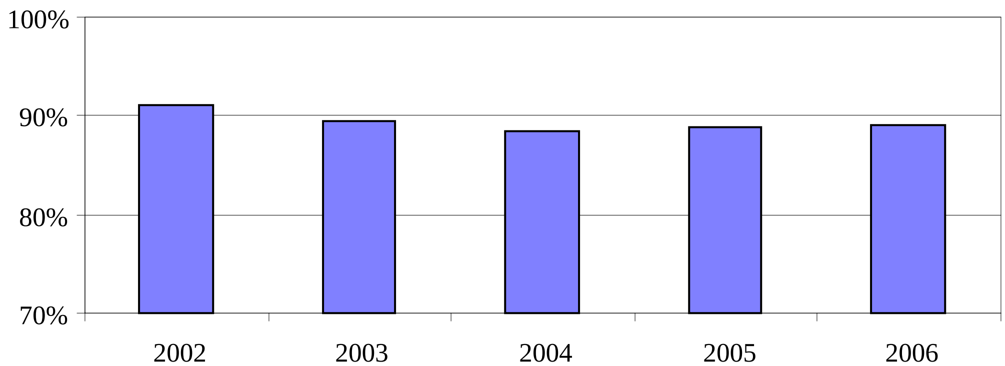
[21] 'B' is intended to indicate budget. The Company's 2007 Capital Budget was approved in Order No. P.U. 30 (2006) and P.U. 34 (2006).

[22] Includes $18.2 million associated with Rattling Brook Hydro Plant Refurbishment.

2.3.1 Customer Satisfaction

Graph 3 shows annual customer satisfaction[23] from 2002 to 2006.[24]

Graph 3
Customer Satisfaction
2002 to 2006



Graph 3 shows that the Company's customer satisfaction rating has remained close to 90 percent since 2002. In 2006, the Company's customer satisfaction rating was 89 percent.

Since 2002, customers have consistently ranked reliability of power as the most important attribute of service followed closely by price of electricity.

2.3.2 Reliability

System reliability is largely a function of the condition of electrical system assets.[25]

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[23] 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 percent 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.

[24] Since 2002, retail rates have increased by over 25 percent.

[25] This is a widely accepted engineering principle. It was recognized in, amongst other places, the 1991 *Report on the Technical Performance of Newfoundland Light & Power Co. Limited*, prepared by George Baker, P.Eng., for the Board.

Reliability is improved by the effective deployment of operational resources to respond to power outages in a timely manner.

Reliability performance[26] is also materially impacted by extreme weather events. For example, in 1994, a sleet storm caused over 216 million customer minutes of outage[27] and increased the average duration of customer outages by 18.4 hours. Weather conditions for the past five years have been moderate, with no major storm damage encountered.

Measuring Reliability

The most common reliability performance measures used in the Canadian electricity business are SAIFI and SAIDI.[28] SAIFI refers to System Average Interruption Frequency Index which is the average number of outages per customer.[29] SAIDI refers to System Average Interruption Duration Index which is the average hours of outage per customer.[30]

[26] Reliability performance is monitored and reported to the Board quarterly. In addition, specific instances where outages exceed 300,000 customer minutes are reported to the Board through Power Outage/Incident Advisory reports by the next business day.

[27] Customer minutes of outage is the total number of customers affected by an outage multiplied by the length of the outage in minutes. For 2006, there was a total of 39,519,713 customer minutes of outage and a SAIDI of 2.98 hours. (39,519,713 divided by 60 divided by 220,709 (customers) equals 2.98).

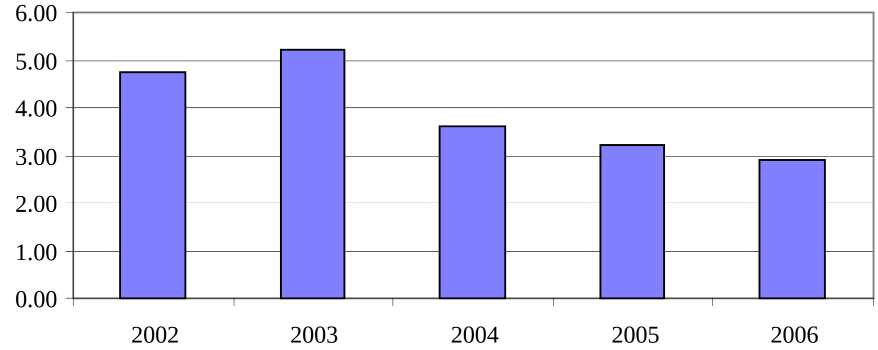
[28] SAIFI and SAIDI are the reliability performance indices used by the Canadian Electricity Association.

[29] SAIFI is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

[30] SAIDI is calculated by dividing the number of customer outage hours by the total number of customers in an area.

Graph 4 shows SAIFI for Newfoundland Power's customers from 2002 to 2006.

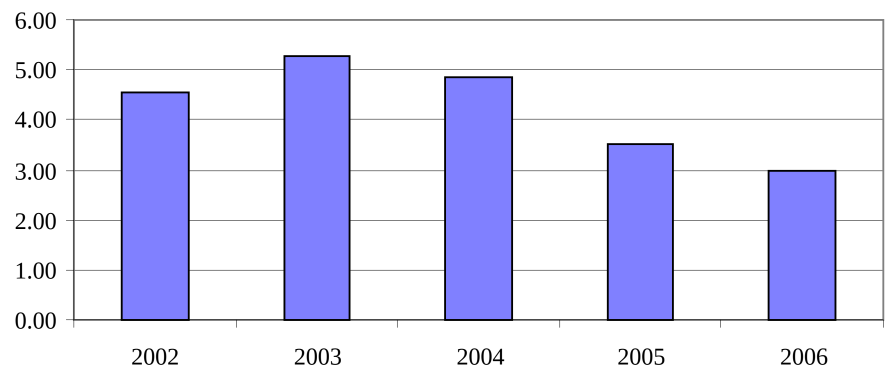
Graph 4
SAIFI
2002 to 2006



Since 2002, the frequency of outages experienced by customers has decreased by 39 percent.

Graph 5 shows SAIDI for Newfoundland Power's customers from 2002 to 2006.

Graph 5
SAIDI
2002 to 2006



Since 2002, the duration of outages experienced by customers has decreased by 34 percent.

Managing Reliability

Newfoundland Power manages system reliability through (1) capital investment[31], (2) maintenance practices, and (3) operational deployment.

(i) Capital Investment

Newfoundland Power is a mature electrical utility. Accordingly, the majority of its annual capital expenditure is devoted to the replacement of aged and deteriorated facilities required to provide safe and adequate service to its customers. These expenditures will tend to improve reliability simply because newer plant is inherently more reliable than older plant.

In addition to the replacement of aged and deteriorated plant, Newfoundland Power examines its actual distribution reliability performance to assess whether targeted capital investment is warranted to improve service reliability. Since 1999, Newfoundland Power has invested approximately $2 million per year, predominantly in rural areas, through its Distribution Reliability Initiative ("DRI").[32]

Under the DRI, the Company identifies the worst performing distribution feeders in the power system based on reliability measures. Customers served by these feeders experience more frequent and longer duration outages than the majority of customers. Engineering assessments

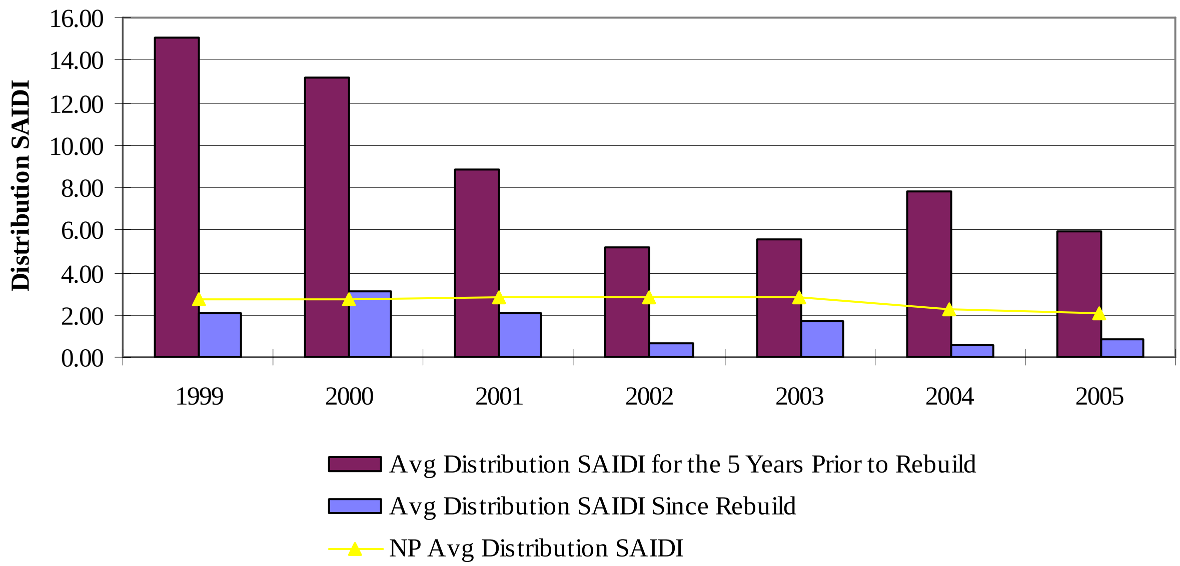
[31] Each year, Newfoundland Power's forecast capital expenditures for the ensuing year are considered and approved by the Board.

[32] Rural distribution reliability (as measured by duration of customer outages) is, on average, materially poorer than urban distribution reliability. From 2002 to 2006, rural distribution outages were, on average, 2 times greater than urban distribution outages. From 1997 to 2001, rural distribution outages were, on average, 2.6 times greater than urban distribution outages.

are produced for each of the worst performing feeders and, where appropriate, the Company makes capital investments to improve the reliability of these feeders.[33]

Graph 6 shows the impact on distribution SAIDI[34] of the DRI undertaken since 1999 on the duration of outages experienced by customers served by the worst performing feeders.[35]

Graph 6
Distribution Reliability Initiative
Distribution SAIDI
1999 - 2005



Through the DRI, SAIDI for the former worst performing feeders has improved and is now comparable with the Company average SAIDI.

[33] When capital work is performed under the DRI, reliability is enhanced by constructing distribution lines to meet Canadian Standards Association standard CAN/CSA C22.3 for heavy or severe wind and ice loading conditions as local conditions require.

[34] System SAIDI is a composite of all outages experienced by customers caused by distribution, generation and transmission. Distribution SAIDI measures all outages experienced by customers due to the distribution system alone.

[35] The two columns per year represent the 5-year SAIDI average (purple) for the worst performing feeders in the years prior to the work being completed, and the average SAIDI (blue) since the work was completed. The yellow line is the average SAIDI for the remainder of the Company's feeders. 2006 is not included because average SAIDI for the worst performing feeders since their rebuild in 2006 will not be available until the end of 2007.

(ii) Maintenance Practices

Newfoundland Power's asset management practices balance the maximization of asset lives with the proactive replacement of deteriorated plant and equipment. However, the longer equipment remains in service exposed to climatic and operational stresses, the greater the likelihood of failure and power outages. To minimize these failures and thereby reduce outages, the Company has maintenance programs in place for all electricity supply assets.

Under the Company's maintenance programs, assets are assigned a frequency at which inspections and, where appropriate, diagnostic testing and equipment overhaul, is performed. Major electrical equipment (such as that in substations) is visually inspected monthly, and infrared inspections and oil analysis are conducted annually.

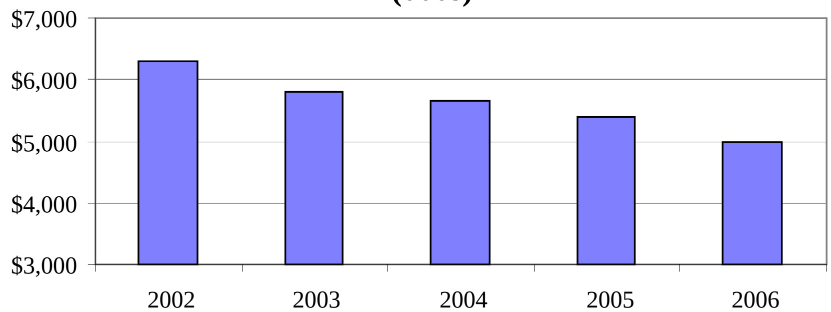
One indication of improvement in maintenance programs is the cost of breakdown maintenance over time. Breakdown maintenance is responsive in nature and is required to restore electricity service after an equipment failure has occurred. The unplanned nature of breakdown maintenance leads to increased costs particularly in overtime labour.

Generally, maintenance performed in a planned manner through capital projects or preventive maintenance programs is less costly than maintenance performed after a breakdown has occurred.[36]

[36] Newfoundland Power spends approximately $16 million per year on electrical system maintenance. To the degree that maintenance is planned, as opposed to in response to breakdowns, improves both (i) the overall productivity of maintenance efforts, and (ii) system reliability.

Graph 7 shows breakdown maintenance costs from 2002 to 2006.

Graph 7
Breakdown Maintenance Cost
2002 to 2006
(000s)



Since 2002, breakdown maintenance costs have decreased by 21 percent or approximately $1.3 million. This is broadly reflective of the improving effectiveness of current maintenance practices.

(iii) Operational Deployment

System reliability is affected by Newfoundland Power's ability to respond to power outages anywhere in the Company's service territory in a timely manner. Newfoundland Power employees and required materials are deployed throughout the service territory to enable the Company to respond quickly to power outages in a safe and efficient manner.[37]

Newfoundland Power has a target to arrive at 85 percent of trouble calls[38] within two hours of being contacted by a customer.

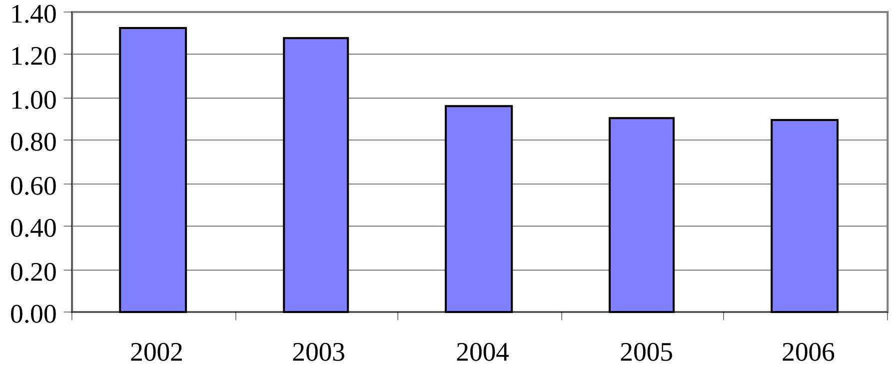
37 Newfoundland Power has linepersons situated in 23 locations across its service territory.

38 Trouble calls include calls from customers reporting no power, part power, flickering lights, fluctuating voltage, blowing fuses or downed wires.

Approximately 28 percent of outages experienced by Newfoundland Power's customers are scheduled outages. Scheduled outages are sometimes necessary for employees to perform system maintenance on the electricity system in a safe manner. Newfoundland Power focuses on minimizing the number and duration of scheduled outages.

Graph 8 shows the contribution of scheduled outages to overall SAIDI from 2002 to 2006.

Graph 8
Scheduled SAIDI
2002 to 2006



Scheduled outage durations have reduced since 2002. This is mainly the result of the increased use of hot-line work methods.[39] As well, the Company ensures that employees, equipment and materials are organized such that scheduled outage durations are minimized.

All scheduled outages are co-ordinated with larger commercial and institutional customers to minimize the effects of the disruption where possible. Scheduled outages are communicated via local media to all customers prior to the start of the outage.

[39] Hot-line work methods refer to work on power lines, using specialized tools, conducted while the lines remain energized at high voltage.

Newfoundland Power and Hydro have formed a reliability committee that initiates and monitors activities to improve reliability for customers of both utilities. A key outcome for the committee was the reduction in outages arising from underfrequency events.[40] There were 17 underfrequency events in 2002 compared to 6 in 2006. In 2002, there were a total of 185,643 customer interruptions resulting from underfrequency events. In 2006, there were 34,605 customer interruptions.[41]

2.3.3 Customer Relations

A significant aspect of Newfoundland Power's service obligation relates to its interactions with its customers. The Company has approximately 3,900,000 interactions with customers each year including metering readings, telephone calls, electricity bills and mail outs, and through the Company website.[42]

Effective management of this volume of customer contacts is a necessary component of least cost service delivery.

Customer Contact Centre

In 2006, the Company received over 530,000 calls from customers at the Customer Contact Centre.

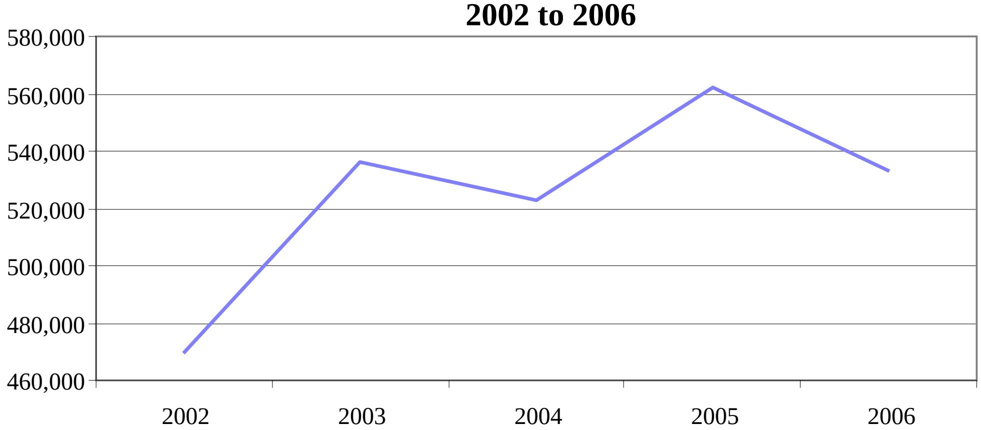
[40] An underfrequency event occurs when there is insufficient generation available to serve the aggregate customer load. This typically results when a major source of generation or transmission circuit experiences a forced outage. When an underfrequency event occurs, supply is automatically disconnected (or shed) from thousands of customers until generation and load is rebalanced.

[41] In addition, Newfoundland Power's Supervisory Control and Data Acquisition ("SCADA") system was enhanced in 2003 to enable the Company to quickly add or remove distribution feeders from the underfrequency load shedding scheme. This permits greater sharing of the impact of underfrequency events across the Company's customer base.

[42] 3,900,000 interactions per year includes approximately 2,700,000 meter readings and electric bills, 380,000 website visits, 535,000 calls to the Customer Contact Centre, 130,000 service orders, 100,000 calls to customers and 16,000 emails.

Graph 9 shows the number of calls received at the Customer Contact Centre from 2002 to 2006.

Graph 9
Calls Received at the Customer Contact Centre
2002 to 2006



Since 2002, calls received at the Customer Contact Centre have been increasing. Billing enquiry calls such as payment arrangements and account changes constitute the highest number of calls received.[43]

Newfoundland Power has also increased the number of services offered at the Customer Contact Centre. For example, since 2005, customer calls regarding technical services such as underground wiring and service poles are now answered at the Customer Contact Centre. Over 11,000 calls were received at the Customer Contact Centre regarding technical services in 2006.

When a customer calls the Customer Contact Centre, the customer has the option of speaking with an employee or using the Interactive Voice Response System ("IVR"). The IVR provides

[43] The proportion of Customer Contact Centre calls related to billing is virtually unchanged since 2002. In 2006, enquiries related to billing and credit matters accounted for 62 percent of all calls. In 2002, it was 61 percent.

automated service to customers.[44] In 2006, approximately 190,000 calls were completed through the IVR. This represents 35 percent of all customer calls to the Customer Contact Centre.

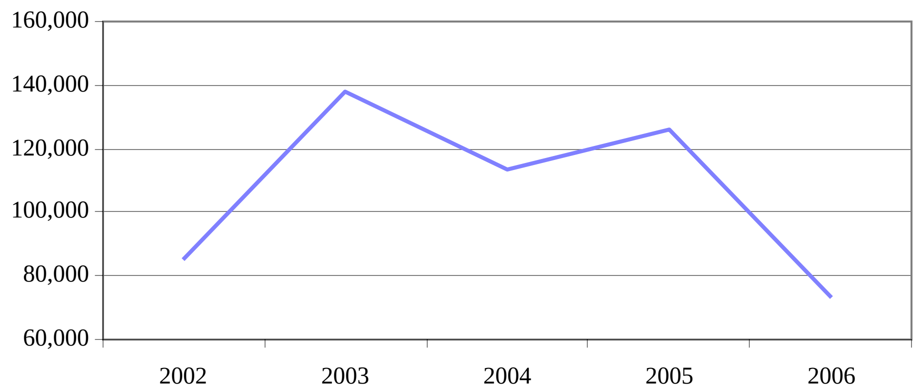
Newfoundland Power has a target to answer 80 percent of customer calls within 40 seconds.

Outage Notification System

During unplanned power outages, customers expect the Company to provide them with information quickly and efficiently. The Outage Notification System ("ONS")[45] provides customers with an automated message containing the reason for the outage and the estimated restoration time.

Graph 10 shows the total number of calls received by the ONS from 2002 to 2006.

Graph 10
Calls Received by the ONS
2002 to 2006



[44] In 2006, approximately 200,000 customers called requesting their account balance. Of these, approximately 90 percent used the IVR to obtain the information while the remainder chose to speak to a Customer Contact Centre employee.

[45] The ONS was implemented in 1998.

In 2006, approximately 73,000 calls were received by the ONS. On average, over 100,000 calls per year were received by the ONS since 2002. The number of calls received by the ONS is dependant upon the reliability of the electrical system.[46]

The ability of the ONS to handle large call volumes is especially important in times of large power outages. For example, on May 9, 2005, a problem on the Island electrical grid affected six Newfoundland Power substations. In total, the power outage affected 29,180 customers in the St. John's area for a total of 31 minutes. During this outage, 10,863 calls were received by Newfoundland Power for information regarding the outage. The Company was able to provide updated information to these customers quickly and cost effectively through the ONS.[47]

The Internet

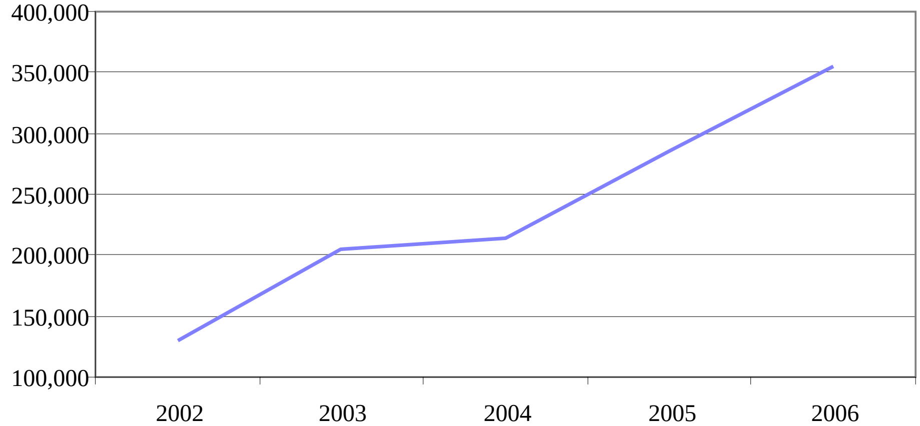
Newfoundland Power's website offers customers 24 hour access to view and change account information. Since its inception, customer usage of the website continues to grow.

[46] The ONS can answer 256 simultaneous calls per minute for each of the Company's 8 operating areas. This provides a technical capacity to respond to 2,048 calls simultaneously across the Company's service territory. Such technical capacity would only be fully utilized if customers were experiencing outages in all operating areas simultaneously.

[47] The operating cost of the ONS for 2006 was approximately $37,000.

Graph 11 shows total customer visits to the Company's website from 2002 to 2006.

Graph 11
Customer Visits to Company Website
2002 to 2006



In 2006, the website was visited approximately 355,000 times by customers, an increase of 174 percent over 2002.[48] As a result of this increasing usage, the Company continues to improve the amount and types of information available to customers via the website. For example, customers can view their account and electrical usage history, review information regarding saving energy and help their children learn about electrical safety and energy efficiency.[49]

The cost per customer transaction on the website is approximately $0.10. This is a fraction of the cost of serving a customer at the Customer Contact Centre.[50]

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[48] Approximately 42 percent of these visits were to review or change their account information.

[49] In February 2007, the Company launched *KidZone*, an online site designed to help kids learn about electrical safety and energy efficiency. This site augments the in-school electrical safety and energy efficiency education programs that have been delivered by the Company to over 27,000 students since 2002.

[50] The operating cost to serve a customer at the Customer Contact Centre is approximately $3.11 per transaction to speak to an employee or $1.18 per transaction to use the IVR.

Electronic billing, or *eBills*, which commenced in 2004, provides customers with the opportunity to receive their electricity bill through email as opposed to receiving a paper copy in the mail. In 2006, over 11,000 customers received their bill through email.[51]

Energy Efficiency

The Company's promotion of efficiency in the use of electrical energy is consistent with the requirement for the provision of least cost supply to its customers. The Company has been active in promoting energy efficiency.

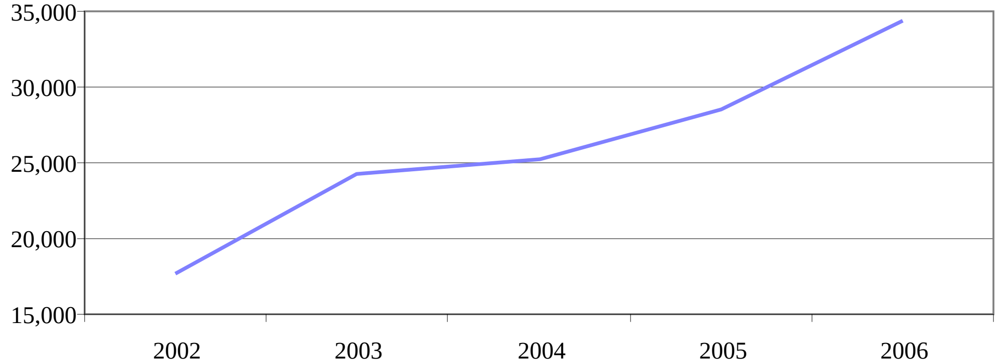
In 2005 and 2006, the Company's *Customer Attitude Survey on Energy Efficiency* found that approximately 35 percent of residential customers plan to take action to reduce energy usage. Approximately, 68 percent of customers indicated that the preferred source for information on efficient use of electricity is their electric utility.[52]

[51] *eBills* savings to the Company are approximately $7.00 per year per customer ($0.10 (paper and processing) plus $0.48 (postage) multiplied by 12 equals $6.96).

[52] This is similar to the Canadian Electricity Association's findings in the annual *Public Attitudes Survey*. The survey found that almost 70 percent of those surveyed felt that the electric utility should provide energy efficiency information.

Graph 12 shows the number of customer contacts regarding energy efficiency since 2002.

Graph 12
Customer Contacts Regarding Energy Efficiency
2002 to 2006



From 2002 to 2006, the number of customers who contacted the Company about energy efficiency information and initiatives increased by 94 percent. To meet this growing need, the Company continues to enhance programs and increase information provision to assist customers with energy efficiency.[53]

53 The increased provision of information to customers in 2006 has been provided, in part, by increasing customer mail outs focused on energy efficiency and, in part, by increasing energy efficiency advertising and community interactions.

Table 13 shows Newfoundland Power's total energy efficiency program costs for 2002 to 2006.

Table 13
Energy Efficiency Program Costs
2002 to 2006
($000s)

	2002	**2003**	**2004**	**2005**	**2006**
Energy Services & Programs[54]	140	139	192	122	118
Energy Advertising[55]	18	25	69	104	96
Wrap Up For Savings	15	6	21	86	81
Demand Management	131	61	77	226	317
Total	**304**	**231**	**359**	**538**	**612**

From 2002 to 2006, costs have increased in response to (i) the increased level of interest in energy efficiency expressed by customers, and (ii) the demand and energy wholesale rate.

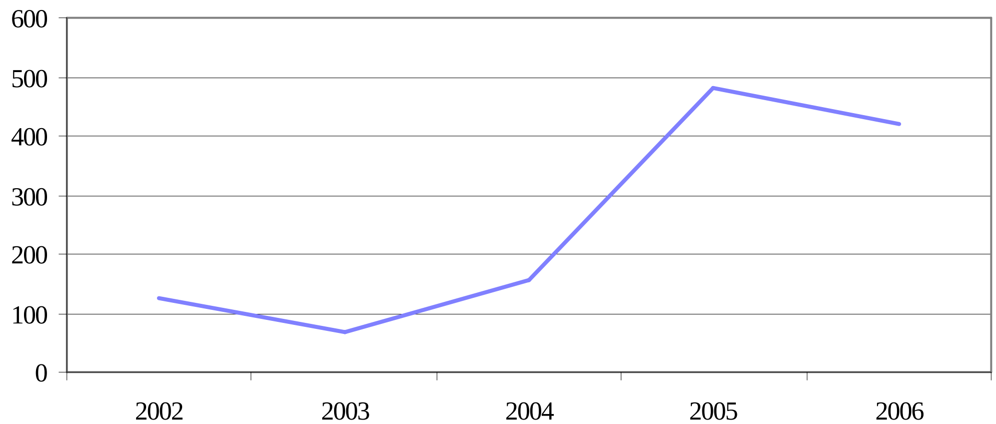
Since 1992, Newfoundland Power has offered customers its *Wrap Up for Savings* insulation rebate program. This program targets efficiencies in home heating by providing financial support for customers' home energy efficiency upgrades.

54 *Energy Services & Programs* is principally composed of allocated Customer Service labour costs associated with responding to customer energy efficiency enquiries and delivering customer programs. In 2005, the Company partnered with Costco in the promotion of compact fluorescent lights ("CFLs"). Energy savings over the life of the CFLs purchased during this promotion is estimated to be 870,000 kWh, or 0.87GWh, compared to the equivalent number of incandescent lights.

55 *Energy Advertising* consists of print media advertising costs.

Graph 13 shows customer participation in the Company's *Wrap Up for Savings* program from 2002 to 2006.

Graph 13
Wrap Up for Savings Program
Customer Participation
2002-2006



Participation in the Company's *Wrap Up for Savings* program has materially increased since 2002. Rebates were increased starting in 2005 and participation increased from 157 customers in 2004 to 483 in 2005 and 422 in 2006. Annual energy savings achieved as a result of customer participation in this program since its launch in 1992 are estimated at over 11.3 GWh. The program has also provided an estimated system demand savings of approximately 3.5 MW.[56]

Newfoundland Power currently has a Curtailable Service Option.[57] The Curtailable Service Option for large general service customers was expanded from 8 customers during the 2004 - 2005

[56] From 1992 to 2006, approximately 3,200 customers have participated in the *Wrap Up for Savings* Program, saving an average of 3,550 kWh and 1.1 kW per year (3,200 times 3,550 kWh equals 11.3 GWh, 3,200 times 1.1 kW equals 3.5 MW).

[57] Costs associated with the Curtailable Service Option are included in *Demand Management Costs* in Table 13. Costs specifically associated with the Curtailable Service Option from 2002 to 2006 were approximately $691,000.

winter peak season to 20 customers in the 2006 – 2007 winter peak season. The addition of these customers increased the peak load reduction from curtailable load to approximately 8 MW.

Newfoundland Power has also taken steps to reduce consumption at its own buildings and facilities during peak load periods. This initiative provides approximately 2 MW of peak load reduction.[58]

The Company is participating in a joint Conservation and Demand Management Potential Study with Hydro in 2007.[59] The Conservation and Demand Management Potential Study will evaluate further conservation and energy efficiency program alternatives and aid in the development of a multi-year plan to implement cost-effective conservation programs for the Newfoundland and Labrador electrical systems.

Customer Demand Requirements

The demand and energy wholesale rate provides an incentive to Newfoundland Power to take reasonable actions to minimize the peak demand requirements of its customers.[60] Newfoundland Power can influence peak demand through pricing and conservation and demand management.[61]

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[58] The Company has also conducted testing of voltage control management as a means of reducing peak period load requirements over the past 2 years. Voltage control management is used by distribution utilities across Canada and the United States during periods of high demand to improve electrical system reliability. The Company has modelled the electrical system and has performed several tests in conjunction with Hydro to assess the extent to which voltage reduction can reduce system peak. Due to the many variables influencing electrical loads, assessing the impact of voltage control management on peak demand is difficult. Further experience with voltage control management initiatives will be required to assess their long-term value.

[59] The Conservation and Demand Management Potential Study is scheduled to be completed in September 2007.

[60] The native 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). The billing demand is computed from the annual native peak less the credit for Newfoundland Power's generation. The billing demand can not be less than the minimum billing demand that is set at 99% of test year billing demand.

[61] The Company's approach to customer pricing is reviewed in *Section 4: Customer Rates and Regulations*.

In general, peak demand is driven by a period of extremely cold weather (i.e., a "cold snap") and normally occurs in the early evening (5 pm to 6 pm). Variability in peak demand from year to year can lead to material changes in purchased power demand costs from those reflected in customer rates. Peak demand varies annually depending on when the cold snap occurs and the actual weather conditions during the cold snap.

When a cold snap occurs during the Christmas season it can result in a relatively high peak demand as a result of the added impact of Christmas load. When the cold snap occurs during March, the level of peak demand will normally be lower because less lighting load is required from customers during the early evenings as the hours of daylight have increased.

Hydro and Newfoundland Power have agreed on a weather normalization mechanism for use in the application of a demand-energy rate. While the weather normalization mechanism generally provides reasonable estimates of adjustments related to weather, it does not (and cannot) eliminate uncertainty with the expected level of peak demand.[62]

In Order No. P.U. 44 (2004), the Board approved the establishment of a reserve as part of its approval of a demand and energy wholesale rate. The existing reserve limits the impacts on the Company of variability in the forecast average cost of purchased power to 1 percent of test year

[62] The 95 percent statistical confidence of the weather normalization mechanism is approximately ± 20 percent. (see: Hydro's *Newfoundland Power Demand and Energy Rate Implementation*, July 2004, p. 10). But even with this level of confidence, material demand uncertainty 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 translated into approximately $1.45 million in supply costs for Newfoundland Power in 2005 (26,000 kW times $4.65 per kW demand charge times 12 months).

demand costs.[63] This provides a meaningful demand management incentive to undertake reasonable initiatives to minimize peak demand.[64]

Based on the experience thus far with the demand and energy wholesale rate, the Company believes that a continued incentive for peak management is appropriate. In this Application, Newfoundland Power is proposing to modify the reserve mechanism to make it explicitly related to demand management.

The proposed Demand Management Incentive Account is provided in Exhibit 4. Transfers to or from the Demand Management Incentive Account are required when the demand supply cost variance is outside the range of 1 percent of test year demand costs.

The proposed Demand Management Incentive Account requires the Company to file an application to the Board no later than March 1st of each year for the disposition of any balance.[65]

To enhance the Board's ability to consider Newfoundland Power's conservation and demand management activities in addressing disposition of any account balances, the Company will

[63] A 1 percent variance in billing demand will cause a variance in purchased power costs from that reflected in customer rates by approximately $520,000 based on the current wholesale demand charge of $4 per kW per month.

[64] Annual savings or costs outside the approved limit are recorded in the Purchased Power Unit Cost Variance Reserve Account (the "Reserve Account"). In 2006, the Reserve Account was credited with an amount reflecting a purchased power cost savings to customers of approximately $2.1 million. This reflects an after-tax savings of $1,342,372. This savings primarily resulted from Newfoundland Power's billing demand from Hydro being approximately 4.7 percent or 52 MW below forecast. The disposition of amounts currently credited to this reserve is reviewed in *Section 3.7.2 Regulatory Reserves*.

[65] This requirement was established under the existing Reserve Account to permit the Board to review the Company's response to the demand and energy rate in determining the disposition of any Reserve Account balances. Lines 16-18, page 13 of Order No. P.U. 44 (2004).

advance the annual filing of its Demand Side Management Report to no later than March 1st of each year.[66]

The Demand Management Incentive Account is consistent with the underlying goals of the demand and energy wholesale rate.[67] Actual experience with the rate will continue to be the most important information to help ensure that the rate form continues to provide the intended results over the long-term. The wholesale demand and energy rate design and the Demand Management Incentive Account will be a subject of ongoing supervision by the Board.

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[66] A practical option to deal with the disposition of balances in the Demand Management Incentive Account would be through the July 1st RSA rate change.

[67] Two of the key issues identified in the *Review of Rate Design for Newfoundland Power*, filed by Hydro at its 2004 General Rate Proceeding, were that the demand and energy wholesale rate: (i) ensure that a meaningful incentive to load management is provided to Newfoundland Power and (ii) avoid undue financial risk or windfall to Newfoundland Power due to weather.

SECTION 3: FINANCE

3.1 OVERVIEW

Newfoundland Power's continued financial integrity and performance are critical to the Company's ability to deliver reliable service at the least cost reasonable. Both the Company and its customers benefit from the sound financial management of Newfoundland Power.

A review of the Company's 2008 forecast financial performance indicates that Newfoundland Power will need regulatory relief to have the opportunity to earn a just and reasonable return in 2008.

This section of Newfoundland Power's evidence reviews financial and regulatory matters including specific directives of the Board relating to rate base, depreciation, employee future benefits, regulatory deferrals and reserves, and inter-corporate relationships.

An increase in current customer rates of approximately 5.3 percent is proposed in this Application.

The principal drivers of this proposed increase are (i) an increased rate of return on common equity for ratemaking purposes, (ii) an increase in depreciation recovery in revenue and (iii) an increase in employee future benefit costs resulting from adoption of the accrual method of accounting for other post employment benefits.

3.2 FINANCIAL PERFORMANCE: 2002 to 2008

This section of the evidence reviews the financial results of operations and forecasts for 2002 to 2008. [1]

Exhibit 5 provides the Company's financial performance for 2002 to 2008.

The 2008 forecast results are based on existing customer rates, and do not include the impact of the proposals set out in this Application. The Company is forecasting a rate of return on rate base of 6.64 percent for 2008.

These forecast results indicate that the Company will need regulatory relief to have the opportunity to earn a just and reasonable return in 2008.

3.2.1 Revenue

Electricity Sales and Revenue

Approximately 69 percent of the Company's retail rate revenue recovers the cost of electricity supplied by Hydro. The remaining 31 percent recovers the Company's costs to operate, maintain and expand the electricity system.

[1] Operating expenses other than pension costs are reviewed in *Section 2: Customer Operations.* The Company's operating expenses were stable from 2002 to 2006. Forecast 2007 and 2008 operating expenses are in line with actual operating expenses in 2002 to 2006.

Table 14 shows electricity sales and revenue from 2002 to 2008E.[2]

Table 14
Electricity Sales and Revenue: 2002 to 2008

	2002	**2003**	**2004**	**2005**	**2006**	**2007F[3]**	**2008E**
Electricity sales (GWh)	4,765	4,882	4,979	5,004	4,995	5,054	5,154
Sales Growth (%)	2.1	2.5	2.0	0.5	(0.2)	1.2	2.0
Electricity Revenue ($000s)							
Revenue from Rates	362,772	376,094	395,577	407,597	407,689	472,155	478,535
2005 Unbilled Revenue[4]	-	-	-	-	3,086	2,714	-
Total	**362,772**	**376,094**	**395,577**	**407,597**	**410,775**	**474,869**	**478,535**

Newfoundland Power's electricity sales are impacted by economic conditions, population changes and demographics, and customer usage patterns.

Electricity sales growth moderated in 2005 and in 2006 modestly decreased compared to 2005. This is attributable to a reduction in customers' average use of electricity. Since 2002, retail rates have increased by over 26 percent.

Forecast electricity sales and revenue for 2007 and 2008 are based upon the Company's most recent sales forecast.[5]

Other Revenue

Other revenue reduces the revenue required from customers through electricity rates.

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2 References to years with the notation 'E' (i.e., 2008E) are intended to indicate *forecast* based on electricity rates effective January 1, 2007 approved by the Board in Order No. P.U. 9 (2007) and *before implementation of any of the proposals in this Application*.

3 References to years with the notation 'F' (i.e., 2007F) are intended to indicate *forecast* based on electricity rates effective January 1, 2007 approved by the Board on interim basis pursuant to Order No. P.U. 41 (2006).

4 In Order Nos. P.U. 40 (2005) and P.U. 39 (2006), the Board approved the amortizations of the 2005 unbilled revenue as current revenue for 2006 and 2007 to offset the income tax effects of the 2005 tax settlement. 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).

5 The customer, energy and demand forecast is found in *Volume 2: Supporting Materials*, *Tab 8.*

Table 15 shows other revenue from 2002 to 2008E.

Table 15
Other Revenue: 2002 to 2008
($000s)

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

The largest component of other revenue is pole attachment revenue. Pole attachment revenue increased from $5.4 million in 2002 to $8.3 million in 2006. This was a result of the Company's acquisition of joint-use poles from Aliant Telecom Inc. over the 5-year period from 2001 to 2005.

Increases in engineering services being provided under contract with Aliant Telecom Inc. and Persona Communications Inc. also contributed to growth in other revenue since 2002.

The 2007 and 2008 forecast reflects further increases in pole attachment revenue based on expected increases in the number of joint-use poles.[8]

3.2.2 Power Supply Cost

Newfoundland Power purchases approximately 90 percent of the electricity it sells to its customers from Hydro. Power supply cost from Hydro currently accounts for approximately 69 percent of electricity revenue.

[6] Miscellaneous revenue includes customer jobbing, wheeling charges, land sales and various fees.
[7] Interest related to the 2005 tax settlement.
[8] The number of joint-use poles is estimated to increase by 3.4 percent from 2006 to 2008.

Table 16 shows power supply cost from 2002 to 2008E.

Table 16
Power Supply Cost: 2002 to 2008

	2002	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008E**
Purchases (GWh)	4604	4725	4841	4872	4875	4970	5032
Power Supply Cost ($000s)							
Purchases from Hydro	210,764	226,332	242,280	254,222	255,425	322,688	328,786
Hydro Production Equalization Reserve[9]		1,732	1,732	1,732	1,732	1,732	
Replacement Energy Cost[10]						(1,795)	
Total	**210,764**	**227,964**	**244,012**	**255,954**	**257,157**	**322,625**	**328,786**
Unit Cost (cents/kWh)	4.58	4.83	5.04	5.25	5.27	6.49	6.53

From 2002 to 2006, increases in power supply cost reflect increases in the cost of fuel burned at Holyrood and purchases required to serve additional customer load requirements.

In 2007, the Holyrood fuel cost included in rates increased from approximately $29 per barrel to $55 per barrel. This is the primary driver of the 23 percent increase in the power supply unit cost from 2006 to 2007.

3.2.3 Pension Costs

Table 17 shows Newfoundland Power's pension and early retirement program ("ERP") costs from 2002 to 2008E.

Table 17
Pension and ERP Costs: 2002 to 2008
($000s)

	2002	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008E**
Pension & ERP	3,972	3,787	4,345	6,369	7,343	5,513	3,348

9 The 5-year amortization of the non-reversing portion of the Hydro Production Equalization Reserve approved by the Board in Order No. P.U. 19 (2003).

10 In Order No. P.U. 39 (2006), the Board approved the deferred recovery of $1.1 million (after-tax) in replacement energy costs related to the Rattling Brook Hydro Plant refurbishment project.

Pension and ERP costs increased by $2.0 million in 2005 compared to 2004, principally due to costs associated with the 2005 ERP.[11]

In 2006, pension costs increased principally due to a 1 percent reduction in the discount rate.[12] The increase was also because of 2005 ERP costs [13] and an *ad hoc* inflationary benefit increase to pensioners effective July 1, 2006.[14] The 2006 increase in pension costs was mitigated by the positive performance of pension plan assets.[15]

The forecast pension costs for 2007 and 2008 also reflects the funding status of the defined benefit plan[16] and the conclusion, in March 2007, of the amortization of retirement allowances related to the 2005 ERP.

3.2.4 Depreciation

Typically, depreciation expense increases annually due to continued investment in the electricity system required to provide service.

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[11] Regulatory treatment of 2005 ERP costs was approved by the Board in Order No. P.U. 49 (2004). Commencing in April 2005, pension costs of $11.3 million and retirement allowances of $1.7 million related to the 2005 ERP are being amortized over 10 years and 24 months, respectively.

[12] The discount rate is used to determine the present value of obligations related to the defined benefit pension plan. The discount rate decreased from 6.25 percent in 2005 to 5.25 percent in 2006. This increased pension expense by approximately $2.4 million. The discount rate is forecast to remain at 5.25 percent for 2007 and 2008.

[13] 2006 pension expense included 12 months of 2005 ERP amortization. Only 9 months of 2005 ERP amortization was recognized in 2005.

[14] Ad-hoc pension increases are increases in pension entitlements granted to fixed income pensioners to offset inflation. The Company's defined benefit plan does not provide for inflation indexing. In 2006, an ad-hoc pension increase was given to all pensioners of the Newfoundland Power pension plan who retired on or before February 1, 1998. The increase in pension costs related to the 2006 ad-hoc inflationary benefit was $2.8 million to be amortized over a 15-year period at a rate of $212,000 per year. A similar *ad hoc* increase was approved in Order P.U. 36 (1998-99) whereby the Board approved a 15-year amortization of costs related to an ad-hoc increase to pensioners.

[15] The return on pension plan assets will reduce pension expense in years where the actual rate of return exceeds the return assumption used in pension valuation.

[16] The December 31, 2005 actuarial report for funding purposes filed with the Application indicates that the Company's defined benefit pension plans past service obligations should be fully funded in 2008.

Table 18 shows depreciation and related cost recovery deferrals[17] from 2002 to 2008E.

Table 18
Depreciation and Related Cost Recovery Deferrals
2002 to 2008
($000s)

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

In 2006, depreciation expense increased by $6.8 million, primarily due to the conclusion in 2005 of a $5.8 million reserve variance true-up adjustment.[18]

In 2005 and 2006, the Board approved cost recovery deferrals of $5.8 million in each of 2006 and 2007.[19] These deferrals offset the increase in depreciation expense in those years attributable to the conclusion of the reserve variance true-up in 2005.

Net depreciation costs are forecast to increase in 2008 by $5.8 million due to the conclusion in 2005 of the reserve variance true-up adjustment. Depreciation expense is forecast to increase by a further $875,000 in 2008 due to continued investment in the electricity system.[20]

3.2.5 Finance Charges

Finance charges are the cost of debt used to finance investment in regulated assets. Finance charges are composed primarily of interest on long-term debt and short-term borrowings.

[17] The cost recovery deferrals were approved by Order Nos. P.U. 40 (2005) and P.U. 39 (2006).

[18] In Order No. P.U. 19 (2003), the Board ordered that a depreciation reserve variance, which resulted from the 2002 depreciation study, be amortized at a rate of $5.8 million per year over 2003-2005.

[19] As a result of the 2006 and 2007 cost recovery deferrals, $11.6 million was deferred until a future Order of the Board. The Company's proposal to recover these deferred costs is described in *Section 3.7.1 Regulatory Deferrals*.

[20] Newfoundland Power's forecast 2008 depreciation expense is more fully reviewed in *Section 3.5 Depreciation.*

Table 19 shows average debt, finance charges and average cost of debt for 2002 to 2008E.

Table 19
Finance Charges: 2002 to 2008

	2002	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008E**
Average Debt ($000s)	345,426	362,620	380,031	391,394	405,665	429,653	450,632
Finance Charges ($000s)	26,853	30,009	30,393	31,369	32,677	33,790	32,775
Average Cost of Debt (%)	7.77	8.28	8.00	8.01	8.06	7.86	7.27

In 2003 and 2005, the Company issued $75 million[21] and $60 million[22] First Mortgage Bonds respectively. These were used to finance the Company's ongoing capital programs.

On January 21, 2005, the Company entered into a stand-alone, 3-year $100 million committed credit facility agreement with a syndicate of Canadian banks.[23] 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.

The average cost of debt is expected to decrease in 2007 and 2008. This is primarily due to the December 2007 maturity of the Series AC First Mortgage Bonds, which carry a coupon rate of 11.875 percent. A 30-year $60 million bond issue is forecast for August 2007 at an interest rate of 5.50 percent.[24]

[21] The issue of Series AJ First Mortgage Bonds was approved by Order No. P.U. 23 (2002-2003) at a rate of 7.520 percent.

[22] The issue of Series AK First Mortgage Bonds was approved by Order No. P.U. 20 (2005) at a rate of 5.441 percent.

[23] The Company was authorized to enter into this facility by Order No. P.U. 1 (2005).

[24] The 5.50 percent interest rate is based on the April 2007, 3 month and 12 month *Consensus Forecast* for 10-year Government of Canada bonds (4.25 percent), plus 2007 spread between 10 and 30 year bonds (0.10 percent), plus an indicative corporate issue spread of 1.15 percent.

3.2.6 Income Taxes

Table 20 shows the Company's income taxes from 2002 to 2008E.

Table 20
Income Taxes: 2002 to 2008

	2002	2003	2004	2005	2006	2007F	2008E
Income Taxes[25] ($000s)	16,381	14,945	15,586	15,368	13,639	12,646	14,256
Effective Income Tax Rate[26](%)	35.8	33.2	33.0	33.0	30.8	30.1	41.1

Between 2002 and 2007, the Company's effective income tax rate decreased by 5.7 percent primarily due to reductions in the federal statutory corporate income tax rate and the elimination of the Large Corporations Tax. The higher effective tax rate for 2008 reflects the conclusion of special pension funding of past service costs. Based on an actuarial valuation completed in 2006, past service costs are expected to be fully funded by March 31, 2008.[27]

3.2.7 Returns on Rate Base and Equity

Table 21 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 2002 to 2008E.

Table 21
Returns: 2002 to 2008
(percent)

	2002	2003	2004	2005	2006	2007F	2008E
Rate of Return on Rate Base							
Midpoint (Approved)	9.94	8.96	8.91	8.68	8.68	8.47	8.47
Actual / Forecast	9.94	9.03	8.82	8.53	8.57	8.12	6.64
Rate of Return on Common Equity	10.65	10.22	10.12	9.60	9.46	8.61	5.85

25 Income taxes in each of 2006 and 2007 include $2.7 million related to the 2005 tax settlement. Income taxes for 2008 include $2.6 million related to the 2005 tax settlement.

26 Includes the effects of 2005 tax settlement. Excluding the effects of the 2005 tax settlement, the effective income tax rates would be 26.5 percent in 2006, 25.3 percent in 2007 and 33.6 percent in 2008.

27 The current actuarial valuation of the Company's defined benefit pension plan is found in *Volume 2: Supporting Materials, Tab 3*.

Newfoundland Power's actual rates of return on rate base for the period 2004 to 2006, and the forecast rate of return on rate base for 2007 and 2008, are below the Board-approved midpoint used for rate setting purposes.[28]

Newfoundland Power's rate of return on rate base for 2003 and 2004 was set by the Board in Order No. P.U. 23 (2003). The allowed rate of return on rate base for 2005 through 2007 was set through operation of the automatic adjustment formula.[29]

3.3 CREDITWORTHINESS

The ability to raise capital in both robust and difficult markets on reasonable terms is consistent with the least cost policy objectives set out in the Electrical Power Control Act, 1994.

Newfoundland Power is targeting the common equity component of its capital structure to be 45 percent and a rate of return on common equity of 10.25 percent for ratemaking purposes in 2008. These targets should maintain the Company's current credit ratings.

An increase in the rate of return on common equity to 10.25 percent from the 8.60 percent currently allowed by the Board for ratemaking purposes will require an increase of approximately 1.9 percent in 2008 revenue.

[28] Returns within the approved range for 2006 and 2007 would not have been achieved but for the approval, in Order Nos. P.U. 40 (2005) and P.U. 39 (2006), of certain accounting accruals and cost recovery deferrals.

[29] By operation of the automatic adjustment formula for 2005, the cost of common equity for rate-making purposes was reduced from 9.75 percent to 9.24 percent. As a result, the Company's allowed rate of return on rate base was reduced from 8.91 percent to 8.68 percent [see Order No. P.U. 50 (2004)]. By operation of the automatic adjustment formula for 2007, the cost of common equity for rate-making purposes was reduced from 9.24 percent to 8.60 percent. As a result, the Company's allowed rate of return on rate base for 2007 was reduced from 8.68 percent to 8.47 percent [see Order No. P.U. 40 (2006)].

This section of the evidence reviews Newfoundland Power's existing credit ratings, its credit metrics and the financial targets that the Company has established to maintain its investment grade rating.

This section of the evidence also outlines the Company's proposals for modifications to the automatic adjustment formula which establishes its annual rate of return on rate base in years subsequent to a test year.

3.3.1 Credit Ratings

An investment grade credit rating allows the Company to have competitive access to capital markets.

The most recent credit rating reports from Dominion Bond Rating Service ("DBRS") and Moody's Investors Services ("Moody's") are found in Exhibit 6.

Table 22 shows DBRS and Moody's current credit ratings for Newfoundland Power.

Table 22
Credit Ratings

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

Newfoundland Power's current credit ratings are investment grade.

Both DBRS and Moody's assess Newfoundland Power's creditworthiness on a stand-alone basis.[30]

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,[31] cash flow interest coverage[32] and cash flow debt coverage.[33]

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 and evaluated the relationship between capital structure, rate of return on common equity and interest coverage.[34]

In recent years, credit rating agencies have placed emphasis on cash flow metrics in their assessment of regulated utilities.[35] This is because principal and interest obligations can only be serviced from cash flows. Regulated earnings do not necessarily mirror cash flows.[36]

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[30] The stand-alone creditworthiness of the Company is reviewed in *Section 3.8.2 Inter-Corporate Relationships*.

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

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

[33] Cash flow debt coverage is (i) cash flow from operations, divided by (ii) the sum of total debt and preferred shares.

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

[35] In the March 5, 2007 credit opinion for Newfoundland Power, Moody's cited the importance of cash flow metrics in the rating of Newfoundland Power.

[36] For example, in 2007 the Company will recognize $2.7 million in 2005 Unbilled Revenue. However, because the 2005 Unbilled Revenue is an accounting accrual as opposed to cash, the impact of the 2007 accrual will be reflected in Newfoundland Power's 2007 earnings but not in its 2007 cash flows.

Table 23 shows the Company's credit metrics from 2002 to 2008E.

Table 23
Credit Metrics: 2002 to 2008

	2002	2003	2004	2005	2006	2007F	2008E
Pre-tax Interest Coverage (times)	2.6	2.4	2.5	2.4	2.3	2.2	2.0
Cash Flow Interest Coverage (times)	3.2	2.9	3.0	2.9	2.7	2.7	2.7
Cash Flow Debt Coverage (percent)	17.6	15.6	16.0	15.7	14.1	13.5	12.6

Table 23 shows that the Company's credit metrics have deteriorated since 2002.[37]

Pre-tax interest coverage has declined from 2.6 times in 2002 to 2.3 times in 2006. Pre-tax interest coverage is forecast to further decline to 2.0 times in 2008 under existing rates.[38]

Cash flow interest coverage declined from 3.2 times in 2002 to 2.7 times in 2006 and is forecast to remain at 2.7 times for 2007 and 2008 under existing rates.

Cash flow debt coverage declined from 17.6 percent in 2002 to 14.1 percent in 2006 and is forecast to decline to 12.6 percent in 2008 under existing rates.

The deterioration in credit metrics in 2006 and 2007 is related to declining returns and the use of accounting accruals and cost recovery deferrals.[39] The use of accruals and deferrals displaced cash revenue in those years that would typically have been recovered in customer rates.

[37] In order to maintain the Company's investment grade credit rating, Moody's requires a cash flow interest coverage of 2.5 times or higher and a cash flow debt coverage of 15 percent or higher. DBRS requires a cash flow debt coverage of 10 percent or higher.

[38] In Order No. P.U. 19 (2003), the Board found that pre-tax interest coverage in the range of 2.4 times is acceptable based upon the Company's business risks, capital structure and rate of return on common equity.

[39] In Order Nos. P.U. 40 (2005) and P.U. 39 (2006), the Board approved the deferred recovery of $5.8 million in each of 2006 and 2007 related to the conclusion of the 2005 depreciation true-up.

The Company's ability to issue further First Mortgage Bonds is dependent on adequate credit metrics, in particular, interest coverage.[40]

3.3.2 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 long-term debt holders, and equity representing the investment of shareholders, in either common or preferred stock.

Table 24 shows the capital structure recommended by Ms. Kathleen McShane, the Company's cost of capital expert.[41]

Table 24
Capital Structure

Debt	53%
Preferred Equity	2%
Common Equity	45%

Credit rating agencies have consistently cited Newfoundland Power's capital structure, which includes 45 percent common equity, as a major strength that mitigates the risk associated with its small size and relatively low forecast growth estimates.[42]

[40] The Company's Trust Deed that secures its Trust Mortgage Sinking Fund Bonds requires, in effect, an Earnings Test interest coverage of 2.0 times or higher for the Company to issue additional bonds to finance its rate base. The Company's 2008 Earnings Test interest coverage, based on January 1, 2007 rates and before any proposals in this Application, is 2.1 times. This is near the bottom of the range at which the Company can issue additional First Mortgage Bonds.

[41] See *Volume 3: Expert Evidence, Tab 1.*

[42] See the DBRS Credit Rating Report (March 9, 2007), pp. 1-2 provided in Exhibit 6.

The Company's target of 45 percent common equity in its capital structure is consistent with Board Orders since 1990.[43]

The Company's cost of capital expert is recommending a range of rate of return on common equity of 10.25 percent to 10.50 percent.[44]

In this Application, Newfoundland Power is targeting a 2008 rate of return on common equity of 10.25 percent for ratemaking purposes. A 2008 increase in the rate of return on common equity for ratemaking purposes from current levels to 10.25 percent will require an increase of approximately 1.9 percent in 2008 revenue.[45]

A common equity component of capital structure of 45 percent, together with a rate of return on common equity of 10.25 percent, will provide Newfoundland Power the opportunity to improve its credit metrics and maintain its investment grade credit rating.

Forecast 2008 Credit Metrics

The arithmetic relationship between capital structure and rate of return on common equity is such that as the common equity component of capital structure decreases, the rate of return on common equity required to reach investment grade credit metrics increases.

[43] See Order Nos. P.U. 1 (1990), P.U. 6 (1991), P.U. 7 (1996-97), P.U. 16 (1998-99), and P.U. 19 (2003).

[44] See *Volume 3: Expert Evidence, Tab 1.*

[45] 10.25 percent minus 8.6 percent (2007 ratemaking return) equals 1.65 percent. 1.65 percent times $364,854,000 (2008 average book equity) equals $6,020,000. $6,020,000 divided by 0.655 (1 – tax rate) equals $9,191,000. $9,191,000 divided by $478,535,000 (2008 revenue at existing rates) equals 1.92 percent.

In this Application, Newfoundland Power is proposing to commence recognition of other post employment benefits ("OPEBs") on an accrual basis commencing in 2008.[46] This proposal has a material impact on the Company's forecast 2008 credit metrics.

Exhibit 7 shows the relationship between the Company's capital structure, the rate of return on common equity and credit metrics on a forecast 2008 basis. The relationship is provided on 2 bases. Page 1 indicates the relationship assuming no change in OPEBs accounting in 2008. Page 2 indicates the relationship assuming the adoption of the accrual method of accounting for OPEBs in 2008.

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.[47]

Table 25 shows the impact of accrual accounting for OPEBs on the Company's 2008 forecast credit metrics.

Table 25
Impact of OPEBs
Forecast 2008 Credit Metrics

	2008E	**2008F**	
		Cash OPEBs	**Accrual OPEBs**
Pre-tax Interest Coverage (times)	2.0	2.7	2.8
Cash Flow Interest Coverage (times)	2.7	3.2	3.3
Cash Flow Debt Coverage (percent)	12.6	16.1	17.1

[46] The Company's OPEBs proposal is reviewed in *Section 3.6 Employee Future Benefits*.
[47] The cumulative difference between the costs recovered from customers and the actual OPEB payments will be treated as a reduction in rate base. This will reduce the rate base financing costs required from customers.

The forecast credit metrics for 2008 should maintain the Company's current investment grade credit rating.

3.3.3 The Automatic Adjustment Formula

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.[48]

In this Application, Newfoundland Power proposes the following changes to the Formula; (i) that the risk-free rate be 5 percent and the risk premium be set at 5.25 percent, as recommended by Ms. McShane in this Application, (ii) that changes in the risk-free rate used in the calculation of the weighted average cost of capital ("WACC") be determined by reference to *Consensus Forecasts*,[49] and (iii) that the arithmetic expression of the formula be changed to reflect the transition to the Asset Rate Base Method ("ARBM") of calculating rate base.

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

Currently, Newfoundland Power's Formula establishes a forward-looking risk free rate by averaging the daily *ask yields* for the three most recent series of long-term Government of Canada bonds for the last five trading days in October and the first five trading days in November.

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48 The Formula was established pursuant to Order Nos. P.U. 16 (1998-99) and 36 (1998-99).

49 Every month, Consensus Economics Inc. surveys over 240 prominent financial and economic forecasters for their estimates on a range of items, including forecast bond yields. The results of its survey – the "consensus forecasts" – are set out in its monthly publication *Consensus Forecasts*.

Canadian automatic adjustment mechanisms similar to the Formula establish the risk-free rate on the forecast of 10-year bond yields set out in *Consensus Forecasts* and a one-month observation period to establish a spread between 10-year and 30-year bonds. The forecast 10-year bond yield is added to the observed spread to estimate a forecast risk-free rate for the succeeding year.

The use of *Consensus Forecasts* is consistent with Canadian regulatory practice.[50] Newfoundland Power proposes that the risk-free rate used in the operation of the Formula be determined in the same manner.

As a result of Newfoundland Power's completion of the transition to the ARBM of calculating rate base, the arithmetic operation of the Formula will require modification.[51]

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50 The regulators which follow this practice include the National Energy Board, British Columbia Utilities Commission, Alberta Energy and Utilities Board and the Ontario Energy Board.

51 The current arithmetic expression of the Formula is:

$$\text{Rate of Return on Rate Base} = \left[\frac{\text{Invested Capital}}{\text{Rate Base}} \times \text{WACC} \right] + \frac{Z}{\text{Rate Base}}$$

Where Z represents amounts which are recognized in the calculation of either weighted average cost of capital or rate of return on rate base, but not both. These amounts include:

(A) Amortization of Capital Stock Issue Expenses (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation.);
(B) Interest on Customer Deposits (Recognized in the weighted average cost of capital calculation but not the rate of return on rate base calculation.); and,
(C) Interest Charged to Construction (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation.).

The transition to the ARBM is considered in *Section 3.4 Rate Base*.

The appropriate arithmetic expression of the Formula following the Company's transition to the ARBM is:

$$\text{Return on Rate Base} = \text{Rate Base} \times \text{WACC}$$

The continued use of invested capital or the Z factor in the Formula is not required following the transition to the ARBM.[52]

3.4 RATE BASE

The full adoption of the asset rate base method brings the Company's calculation of rate base into the mainstream regulatory practice in Canada and provides for consistent regulatory treatment within this province.

The Company's forecast 2008 average rate base, based on the Company's proposals in this Application, is $809 million.

This section of the evidence addresses the completion of the Company's transition to the asset rate base method and the forecast 2008 rate base.

[52] Conceptually, under the ARBM there will be no unreconciled differences between invested capital and rate base in the calculation of the rate of return on rate base. Under the ARBM, the weighted average cost of capital effectively becomes the rate of return on rate base. The Z factor differences have all been reconciled to the ARBM as part of Newfoundland Power's transition to the ARBM.

3.4.1 Asset Rate Base Method

In Order No. P.U. 19 (2003), the Board found that the ARBM should be used to calculate Newfoundland Power's rate base. The Company has subsequently implemented Board approved rate base changes that have substantially conformed its rate base to the ARBM.[53]

A Report on the Implementation of the Asset Rate Base Method is found in *Volume 2: Supporting Materials, Tab 1* which details the remaining matters required to be addressed for the Company's transition to the ARBM.

Completion of the Company's transition to the ARBM practically requires that the remaining differences between Newfoundland Power's average rate base and its average invested capital ("Reconciling Items") be addressed.[54] The remaining Reconciling Items are (1) other assets and liabilities and (2) rate base allowances. In addition, unamortized deferred debt issue costs, which are currently included in rate base, will be addressed.

Other Assets and Liabilities

Other assets and liabilities are items which are reflected in the Company's invested capital but are not currently reflected in the Company's rate base. They result from the Company's regulated operations.

[53] The transition to the ARBM began with the inclusion of deferred charges in rate base pursuant to Order No. P.U. 19 (2003). In Order No. P.U. 40 (2005), the Board approved that (i) the unamortized 2005 Unbilled Revenue Liability be subtracted from its rate base and (ii) book equity be used in the calculation of the rate of return on rate base.

[54] The Reconciling Items were originally identified by Grant Thornton in its April 4, 2003 Supplementary Evidence filed in the Company's 2003 general rate proceeding.

The other assets and liabilities include: (i) the remaining customer finance programs receivables;[55] (ii) customer security deposits;[55] (iii) the accrued pension liability;[55] (iv) the municipal tax liability;[56] and (v) the accrued OPEBs liability.[57]

Under the ARBM, the other assets will be added to Newfoundland Power's rate base and the other liabilities will be subtracted from its rate base.[58] This will eliminate the differences between average invested capital and average rate base arising as a result of these Reconciling Items.

Table 26 shows the impacts on forecast 2008 average rate base resulting from the inclusion of other assets and liabilities in the Company rate base.

Table 26
Other Assets and Liabilities
Impacts on 2008 Average Rate Base
($000s)

Customer Finance Programs Receivables	1,728
Customer Security Deposits	(736)
Accrued Pension Liability	(3,003)
Municipal Tax Liability	(3,679)[59]
Accrued OPEBs Liability	(3,183)
Rate Base Impact	**(8,873)**

55 Customer finance programs receivables (related to energy efficiency programs), customer security deposits, and the accrued pension liability were identified as reconciling items in Exhibit NP-9 filed in the Company's 2006 Accounting Policy Application. Financing programs balances related to contributions in aid of construction are currently included in the Company's computation of rate base.

56 The municipal tax liability represents a timing difference between the recovery and payment of municipal taxes. Under the invested capital method, the $4.1 million municipal tax liability effectively reduced the Company's invested capital and, in turn, its allowed return and revenue requirement. In this way, the cash flow benefits to the Company associated with the liability were passed on to customers. As part of the transition to the ARBM, the $4.1 million municipal tax liability should be subtracted from rate base, thus reducing Newfoundland Power's allowed return and revenue requirement in a conceptually similar manner. The municipal tax liability is considered further in *Section 3.7.1 Regulatory Deferrals.*

57 The accrued OPEBs liability is proposed to be deducted from rate base as opposed to being treated as zero-cost capital as done by Hydro. The deduction of the accrued OPEBs liability from rate base is conceptually consistent with the Company's current treatment of deferred charges related to pensions. Deducting the accrued OPEBs liability from rate base has the same impact on customers as treating the accrued OPEBs liability as zero-cost capital. The Company's OPEBs proposals are considered in *Section 3.6, Employee Future Benefits.*

58 This is conceptually similar to the treatment of deferred charges approved in Order No. P.U. 19 (2003).

59 This differs from the $4.1 million in *Section 3.7.1 Regulatory Deferrals* as it reflects the proposed 5-year amortization as reviewed in that section. This value is calculated as $4,087,000 (opening balance) minus $817,000 (2008 amortization) divided by 2 (to reflect *average* rate base) equals $3,679,000.

The Company's forecast 2008 average rate base is reduced by $8.9 million due to the inclusion of other assets and liabilities in rate base.

Rate Base Allowances

It is mainstream regulatory practice for a utility's rate base to include allowances for (i) funds used during construction ("AFUDC"), (ii) cash working capital and (iii) materials and supplies.[60] Under the ARBM, there will continue to be differences between average invested capital and average rate base for these items. As these allowances are a component of the Company's rate base, it is appropriate that they be considered as part of the transition to ARBM.

(i) AFUDC

Construction work in progress is not included in average rate base because the related plant is not yet used and useful in providing service to customers.

To provide a utility with a reasonable opportunity to recover the financing costs associated with construction work in progress, an AFUDC is typically provided in rate base.[61] The AFUDC should reflect the cost of financing all construction work in progress, including capital materials and supplies that are to be used to expand the electricity system.

In 2008, AFUDC will reflect the cost of financing capital materials and supplies used to expand the electricity system and will be calculated using the WACC.[62]

[60] Hydro's rate base includes these 3 allowances in addition to a fuel inventory allowance.

[61] The Company currently recovers financing costs associated with construction work in progress through interest during construction, or IDC, which is the conceptual equivalent of AFUDC.

[62] The cost of financing capital materials and supplies used to expand the electricity system are currently recovered through their inclusion in the Company's invested capital.

Mainstream regulatory practice in Canada is to use the WACC to calculate the AFUDC.[63] It is also consistent with the ARBM.

The forecast AFUDC for 2008 is $298,000.[64]

(ii) Cash Working Capital Allowance

Under the ARBM, the inclusion of a cash working capital allowance in the rate base provides a reasonable opportunity to recover the cost of financing working capital.

Newfoundland Power's cash working capital allowance is currently 1.7 percent of its total regulated operating expenses. The 2008 cash working capital allowance based on the Company's lead/lag study is 2.1 percent of its regulated cash operating expenses.

The Company's Cash Working Capital Lead/Lag Study is found in *Volume 2: Supporting Materials, Tab 2*.

The forecast 2008 cash working capital allowance is $9,340,000.

(iii) Materials and Supplies Allowance

The inclusion of a materials and supplies allowance in the rate base provides a reasonable opportunity to recover the cost of financing operating and capital materials and supplies used to maintain the electrical system.

[63] Of 26 surveyed Canadian utilities that follow the ARBM, all but those regulated by the Ontario Energy Board use the WACC to calculate the AFUDC, including Hydro.

[64] Actual AFUDC for 2008 will be included in the 2009 rate base. The forecast 2007 IDC is $420,000.

Capital inventory related to the expansion of the electricity system is excluded from the Company's materials and supplies allowance as it is not yet considered used and useful in providing electricity service.

The 2008 material and supplies allowance is calculated using a 13-month average.[65]

Newfoundland Power's capital inventory related to expansion is currently 18.3 percent of its total capital and operating materials and supplies.[66] The 2008 capital inventory related to expansion is 19.4 percent of the Company's forecast 2008 total capital and operating materials and supplies.[67]

The forecast 2008 materials and supplies allowance is $4,427,000.

Other ARBM Matters

Newfoundland Power's unamortized deferred debt issue costs are currently included in the Company's rate base.[68] The amortization of deferred debt issue costs is included in the calculation of the Company's WACC.

As both unamortized deferred debt issue costs and the amortization of those costs are related to the cost of capital, it is appropriate that they both be included in the calculation of the WACC.[69]

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[65] Newfoundland Power's materials and supplies allowance is currently calculated using a 12-month average. This method of averaging, because it does not consider materials and supplies on hand at the beginning of the year, captures only the changes in inventory levels for the months of February through December. A 13-month average captures the changes in inventory levels for all 12 months of the year and is consistent with the approach used by Hydro.

[66] Approved in Order No. P.U. 1 (1974).

[67] The increase in the percentage of capital inventory related to expansion, from 18.3 percent to 19.4 percent, serves to reduce the materials and supplies allowance included in the Company's rate base.

[68] Deferred debt issue costs associated with bond issues include legal and flotation costs.

[69] This is consistent with the current practice of Hydro.

This would require that unamortized deferred debt issue costs be excluded from Newfoundland Power's rate base.

Impact on Rate Base

Table 27 shows the impacts of the Company's ARBM transition on the forecast 2008 average rate base.

Table 27
2008 ARBM Proposals
Impacts on 2008 Average Rate Base
($000s)

Other Assets and Liabilities	(8,873)
AFUDC[70]	-
Cash Working Capital Allowance	2,527
Materials and Supplies Allowance	(66)
Deferred Debt Issue Costs	(3,368)
Rate Base Impact	**(9,780)**

Newfoundland Power's completion of the transition to the ARBM will result in a decrease the Company's 2008 average rate base of approximately $9.8 million.

3.4.2 Forecast 2008 Rate Base

The Company's forecast 2008 average rate base is approximately $809 million.

Exhibit 8 shows the 2008 forecast average rate base.

[70] In the calculation of average rate base under the ARBM, the AFUDC effectively shifts the costs of financing construction work in progress to the years in which the related assets become used and useful. Therefore, there are no 2008 rate base impacts resulting from 2008 AFUDC. However, there will be interest during construction capitalized in 2008 related to 2007 work in progress.

Changes to the Company's forecast 2008 average rate base are principally the result of two factors: 1) plant investment which includes annual capital expenditures,[71] and 2) depreciation expense.[72] Changes to the rate base required to complete the transition to the ARBM are reflected in the forecast 2008 average rate base.

The forecast 2008 average rate base includes the Company's forecast capital expenditures for 2007 which were approved in Order Nos. P.U. 30 (2006) and P.U. 34 (2006). Forecast 2008 capital expenditures of $52.9 million are also included in the calculation of the forecast 2008 average rate base.

3.5 DEPRECIATION

The Company has filed a 2006 Depreciation Study with this Application.

Based on the 2006 Depreciation Study, the Company proposes to implement new depreciation rates and amortize an accumulated reserve variance beginning in 2008.

Increased depreciation recovery primarily as a result of the conclusion in 2005 of the depreciation true-up as proposed in this Application results in an approximate 1.9 percent increase in 2008 revenue.

This section of the evidence addresses matters related to the 2006 Depreciation Study and 2008 depreciation expense.

[71] Each year, the Company's capital expenditures are considered and approved by the Board. Further detail on the capital forecast is provided in *Section 2.2.3 Capital Forecast.*

[72] Annual depreciation expense is calculated using the composite depreciation rates approved by the Board.

3.5.1 2006 Depreciation Study

Section 69 of the *Public Utilities Act* provides for the creation and maintenance of a depreciation account whereby, over the useful life of the various asset classes, the capital assets costs are expensed as a cost of providing electrical service.

Depreciation expense is calculated on the basis of rates of depreciation assigned to each class of the Company's assets. The Board's practice is to approve depreciation for ratemaking purposes based upon studies of experts who examine the various asset classes and determine the average service life of those assets for depreciation purposes.[73]

The 2006 Depreciation Study ("the 2006 Study"), prepared by Gannett Fleming, was based upon the plant in service as at December 31, 2005.[74]

A copy of the 2006 Study is filed in *Volume 3: Expert Evidence, Tab 3*.

[73] Since 1996, Newfoundland Power has retained Gannett Fleming Valuation and Rate Consultants, Inc. ("Gannett Fleming") to perform depreciation studies of Company plant in service. See Order Nos. P.U. 7 (1996-97) and P.U. 19 (2003).

[74] In Order No. P.U. 19 (2003), the Board ordered Newfoundland Power to file its next depreciation study as of December 31, 2006. The timing of the filing of this Application necessitated that the depreciation study be based on plant in service at December 31, 2005.

Depreciation Rates

Table 28 shows both existing annual depreciation rates and those recommended in the 2006 Study by asset class.

Table 28
Annual Depreciation Rates
(percent)

Asset Class	Existing	2006 Study
Hydro Production	2.03	2.17
Other Production	3.91	4.73
Substation	2.60	2.63
Transmission	3.27	3.28
Distribution	3.29	3.14
General		
Computer – Hardware	20.00	20.00
Computer – Software	10.00	10.00
Transportation	9.44	10.28
Other	2.99	2.94
Communications	7.16	6.18
Composite Rate	**3.5**	**3.4**

The 2006 Study recommends a decrease in the composite depreciation rate which will serve to reduce the amount of depreciation expense that would otherwise be required to be recovered in customer rates.

Accumulated Reserve Variance

Consistent with previous depreciation studies, the 2006 Study provides a comparison between the accumulated depreciation recorded by the Company with respect to plant in service as of December 31, 2005 and a calculated, or theoretical, reserve based on the new depreciation rates recommended in the 2006 Study. The difference is referred to as the accumulated reserve variance. In the 2006 Study, Gannett Fleming has calculated the accumulated reserve variance as at December 31, 2005 to be $0.7 million.[75]

3.5.2 2008 Depreciation Expense

Newfoundland Power proposes to implement the depreciation rates resulting from the 2006 Study effective January 1, 2008.

Newfoundland Power also proposes to amortize the accumulated reserve variance of $0.7 million evenly over four years commencing January 1, 2008. The conclusion of the amortization will coincide with the next depreciation study, which is expected to be completed in 2011 (based upon December 31, 2010 plant in service). This reflects the Board's previous observations regarding the imprecise nature of depreciation true-up and the principle of intergenerational equity.[76]

[75] Gannett Fleming recommends that where the accumulated reserve variance as at December 31, 2005 exceeds 5 percent on an individual account basis, the accumulated reserve variance for that account be amortized over the account's composite remaining life. That recommendation is reflected in Schedule 2 of the 2006 Study.

[76] In Order No. P.U. 19 (2003), the Board considered Gannett Fleming's recommendation that the accumulated reserve variance be amortized over the composite remaining life of the related plant. The Board observed that this would result in accumulated reserve variance not being fully amortized by the time of the next depreciation study. The Board also recounted its earlier finding in Order No. P.U. 7 (1996-97) that an alternate approach of amortizing the accumulated reserve variance over the period between depreciation studies has the quality of intergenerational equity. In Order No. P.U. 7 (1996-97), the Board approved the amortization of an accumulated reserve variance over the five-year period between depreciation studies. In Order No. P.U. 19 (2003), the Board approved a three-year amortization period based on the anticipated filing of a depreciation study in 2006.

Table 29 summarizes the impact of the (i) use of the depreciation rates contained in the 2006 Study and (ii) the four year amortization of the accumulated reserve variance on forecast depreciation expense for 2008.

Table 29
2008 Depreciation Expense
($000s)

Depreciation Expense - Current Depreciation Rates	41,002
Adjustment for Proposed Depreciation Rates	(621)
Adjustment for Reserve Variance Proposal	(174)
Revised Depreciation Expense	**40,207**

Table 29 shows that Newfoundland Power's proposals reduce the amount of depreciation expense required to be recovered in customer rates by approximately $0.8 million per year.

Currently, Newfoundland Power's revenues do not provide full recovery of depreciation costs. This is primarily the result of the use of cost recovery deferrals to offset the impact of the 2005 conclusion of the depreciation true-up.[77]

Commencing in 2008, Newfoundland Power is seeking to fully recover its depreciation costs in customer rates.

[77] The fact that current rates do not provide recovery of the amount of the depreciation true-up was recognized in Order Nos. P.U. 40 (2005) and P.U. 39 (2006). This fact was a justification for the use of cost recovery deferrals in relation to depreciation in 2006 and 2007. Amortization of these cost recovery deferrals is reviewed in *Section 3.7 Regulatory Deferrals and Reserves*.

Newfoundland Power's proposals in this Application will result in full depreciation cost recovery which translates into a revenue increase of approximately 1.9 percent in 2008.[78]

3.6 EMPLOYEE FUTURE BENEFITS

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

Pension Plans are currently accounted for on an accrual basis. Other post employment benefits are currently accounted for on a cash basis.

In Order No. P.U. 19 (2003), the Board directed the Company to propose a plan for moving towards the accrual method of accounting for other post employment benefits with its next general rate application.

To implement Newfoundland Power's proposals for accounting for employee future benefits will require a revenue increase of 1.5 percent in 2008.

This section of the evidence reviews the Company's employee future benefits and reviews proposals to move to the accrual method of accounting for other post employment benefits and the tax accrual method of accounting for pensions and other post employment benefits commencing in 2008.

[78] Depreciation recovery in 2007 was $34,334,000 (see Table 18, $40,127,000 depreciation expense minus $5,793,000 depreciation cost recovery deferral). Depreciation recovery in 2008 is forecast to be $40,207,000. The increase in the 2008 depreciation costs over 2007 is $5,873,000 ($40,207,000 minus $34,334,000). This increases the 2008 depreciation recovery by $8,966,000 ($5,873,000 divided by (1 minus 34.5 percent tax rate)). This will result in a revenue increase of 1.87 percent in 2008 ($8,966,000 divided by $478,535,000 (existing rate revenue)).

3.6.1 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 benefits plans.

The Company maintains both defined benefit and defined contribution pension plans. Defined benefit plans typically provide retirement income based upon an employees' pay at the time of retirement. Defined contribution plans provide retirement income based upon the contributions made by the Company and the employee together with accrued returns on those contributions.[79] 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[80] and health, medical and life insurance for retirees and their dependents.

3.6.2 Pension Plans

Newfoundland Power's principal pension plan is its defined benefit pension plan. There are currently 565 employees participating in this plan.[81]

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[79] Defined contribution pension arrangements have become relatively 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.

[80] Retirement allowances are 1 week's salary per year of service up to a maximum of 20 week's allowance.

[81] In addition, at December 31, 2005 the defined benefit pension plan provided retirement income to a total of 673 retirees and their survivors.

Table 30 shows the costs of Newfoundland Power's defined benefit and defined contribution pension plans from 2002 to 2008F.[82]

Table 30
Pension Plan Cost
2002 to 2008F
($000s)

	2002	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008F**
Defined Benefit Pension Plans	3,161	2,970	3,669	4,615	5,880[83]	4,507	2,441
Defined Contribution Pension Plans	811	817	676	742	839	872	907
Total Pension Costs	**3,972**	**3,787**	**4,345**	**5,357**	**6,719**	**5,379**	**3,348**

The defined benefit pension plan was created in 1984.[84] At the time of its creation, there existed an initial unfunded liability of over $48 million.[85] The plan is expected to be fully funded in 2008.

The current actuarial valuation of the Company's defined benefit pension plan is found in *Volume 2: Supporting Materials, Tab 3.*

At December 31, 2006, the defined benefit pension plan held assets of approximately $250 million. Benefits of approximately $12 million were paid by the plan to Company retirees and survivors in 2006.

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82 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.

83 Increased defined benefit plan costs in 2006 primarily reflect changes in the discount rate used to value plan obligations.

84 The creation of the defined benefit pension plan was, in part, motivated by the provincial government's enactment of *An Act Respecting Pension Benefits* in 1983.

85 In Order No. P.U. 37 (1984), the Board approved the Company's recovery of current pension costs in rates and the amortization of the initial unfunded liability of $48.4 million over 25 years.

Pension funding for the Company's defined benefit pension plans is an actuarially determined amount that, when combined with employee contributions, is expected to be sufficient to satisfy future benefits payments as they become due.[86] The two components of pension funding are: current service funding and past service, or special, funding.[87] Pension funding, because it is deductible in the computation of corporate income tax, reduces customer rates by reducing income tax expense.[88]

The decline in special funding resulting from the plan being fully funded in 2008 will increase the Company's income tax expense.[89] However, a fully funded pension plan can be expected to benefit customers through a reduction in the amount of pension expense included in customer rates.[90]

3.6.3 OPEBs Accounting Proposal

Currently, Newfoundland Power recognizes costs associated with OPEBs on a cash basis as opposed to an accrual basis.[91] The cash cost of OPEBs in 2008 is forecast to be $1.1 million.

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86 Pension legislation requires that funding be based on actuarial valuations that are to be conducted, at a minimum, once every three years. Newfoundland Power's most recent actuarial valuation was performed as of December 31, 2005 (the "2005 Actuarial Valuation").

87 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 the initial unfunded liability of over $48 million.

88 Because pension expense and pension funding are determined with reference to different criteria, the amount of pension cost expensed for accounting purposes in a given year can differ from pension funding. Over time, the divergence between pension expense and pension funding has resulted in the creation of a deferred charge. The inclusion of average deferred charges, including the deferred pension asset, in Newfoundland Power's average rate base was approved by the Board in Order No. P.U. 19 (2003).

89 In 2008, the forecast reduction in pension funding will cause income tax expense to increase by approximately $2.0 million. ($5.7 million (reduction in special funding) times 34.5 percent (tax rate) equals $2.0 million.)

90 In 2008, the forecast reduction in pension expense attributable to the defined benefit pension plan is approximately $2.1 million. See Table 30.

91 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 both the amounts *paid* and the *future obligations accrued in that year*, as estimated by the Company's actuary.

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.[92]

The Company's report on Employee Future Benefits including the adoption of the accrual method of accounting for OPEBs is found in *Volume 2: Supporting Materials, Tab 4*. Accrual accounting for OPEBs expense is the mainstream regulatory practice in Canada.[93] 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 expense for regulatory purposes effective January 1, 2008.

Table 31 shows forecast 2008 OPEBs expense calculated on a cash basis and the accrual basis of accounting.

Table 31
2008 OPEBs Expense
($millions)

Cash Method	1.1
Accrual Method	7.5
Difference	**6.4**

Table 31 shows that OPEBs expense will increase by $6.4 million in 2008 if the Company adopts the accrual method of accounting for OPEBs.

[92] 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. The current actuarial valuation of the Company's OPEB obligations on an accrual basis is found in *Volume 2: Supporting Materials, Tab 5*. As at December 31, 2006, Newfoundland Power's OPEB obligations to employees were valued at $69.8 million on an accrual basis.

[93] Of 26 Canadian utilities surveyed, 18 use the accrual method, including Hydro.

Transitional Matters

There are significant transitional obligations associated with the change in accounting policy. Therefore, 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.[94]

The transitional obligation associated with the Company's adoption of the accrual method of accounting for OPEBs in 2008, as opposed to 2000, is $34.1 million.[95]

Newfoundland Power is proposing that the disposition of this legacy transitional obligation be addressed at the Company's next 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 customers' rates.[96]

Newfoundland Power's OPEBs proposal, if approved by the Board, will mark significant progress in improving current recovery of OPEBs costs.[97]

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94 This was recognized by the Board in Order No. P.U. 19 (2003) at pp. 82-83.

95 If the Company adopts the accrual method of accounting for OPEBs in 2008, as proposed in this Application, this $34.1 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. $34.1 million represents, in effect, the difference between use of the cash and accrual methods of accounting for OPEBs for the period 2000 to 2007.

96 For Newfoundland Power to fully recognize its total OPEBs obligations, including the legacy transitional obligation in 2008, would result in an increase in 2008 revenue requirements of approximately 3 percent (see: *A Report on Employee Future 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 2008 revenue requirements of approximately 1.5 percent.

97 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 $34.1 million, the estimated rate impact (based on the existing 2008 forecast revenue of $478,535,000) would be approximately 1.4 percent. A 10-year amortization would result in an estimated rate impact of approximately 0.7 percent.

3.6.4 Tax Treatment of Employee Future Benefits

The *Income Tax Act (Canada)* only allows tax deductibility for cash outlays made in respect of employee future benefits. For pension plans, this includes plan funding (for defined benefit plans) and contributions (for defined contribution plans) made by the Company for a particular year. For OPEBs, this includes the actual costs for retiree benefits paid by the Company for a particular year.

Accrued employee future benefits, which are actuarially determined, are not tax deductible.[98] In order to mitigate the impact on customers of adopting the accrual method of recognizing OPEBs in 2008, the Company is proposing to adopt the accrual method of income tax accounting on employee future benefits costs in 2008.

Adopting accrual accounting for income tax relating to employee future benefits for regulatory purposes results in recognizing both the costs of the benefits and the related income tax effects of those costs in the same period.[99] This approach will result in the current cost of employee future benefits being offset by the related income tax effects (deductions), even though those income tax effects (deductions) will not occur until future years.[100] The matching of employee future benefits costs to the associated income tax effects will tend to smooth the impact on customer rates

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98 This type of treatment, where an expense recognized for financial reporting purposes is not recognized for income tax purposes, is conceptually similar to the treatment of plant investment recovery by federal tax authorities. Under the *Income Tax Act (Canada)*, only set capital cost allowances established by federal taxation legislation and regulations are deductible for income tax purposes. Depreciation expense, which is typically determined by estimates based upon plant life, is not deductible for income tax purposes.

99 Newfoundland Power currently follows the *Flow-through Method* of recognizing income taxes on its employee future benefits. The *Flow-through Method* recognizes only current (i.e. cash) income taxes. In order to tax-effect its employee future benefits, Newfoundland Power would follow the *Tax Accrual Accounting* for employee future benefits which recognizes both current and future income taxes. In Order Nos. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company's use of the *Tax Accrual Accounting* to recognize future income tax liabilities associated with plant investment.

100 This effect is consistent with the cost of service standard and the principle of intergenerational equity.

associated with fluctuations in employee future benefits costs.[101] This is conducive to rate stability.

The impact in 2008 of adopting accrual accounting for income tax relating to employee future benefits expense is a reduction in Newfoundland Power's income tax expense. This will mitigate the impact on customer rates of the adoption of the accrual method of accounting for OPEBs in 2008.

Newfoundland Power proposes to adopt accrual accounting for income tax related to employee future benefits effective January 1, 2008 concurrent with its adoption of accrual method of accounting for OPEBs.

The adoption of the accrual method of accounting for OPEBs will have implications for the determination of the Company's rate base. The Company proposes that the resulting average net accrued OPEBs liability[102] be subtracted from its average rate base.[103] The reduction in rate base reduces Newfoundland Power's permitted return and revenue requirement. In this way, the cash flow benefits associated with the increased OPEBs expense under the accrual method are passed on to customers.

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[101] To illustrate, each $100 increase in OPEBs expense would be accompanied by a $35 decrease in income tax expense (assuming a 35 percent marginal income tax rate). Therefore, the total cost included in customer rates would be $65 rather than $100. For funded pension plans, changes in pension funding would no longer impact annual income tax costs in the year of funding. Income tax costs related to defined benefit pension plans would be recognized as pension expense is recognized. This will tend to reduce the annual cost volatility associated with differences between pension plan funding and expense.

[102] The net accrued OPEBs liability is the cumulative amount by which recognized OPEBs expense has exceeded OPEBs payments.

[103] This treatment is consistent with the rate base treatment of the deferred pension asset related to the Company's defined benefit pension plans as approved in Order No. P.U. 19 (2003).

Table 32 shows the aggregate 2008 test year costs associated with the Company's employee future benefits proposals.

Table 32
Employee Future Benefits Proposals
2008 Costs
($millions)

Accrual Accounting for OPEBs	6.4
Tax Accrual Accounting for Employee Future Benefits	(1.5) [104]
Rate Base Effects	(0.2) [105]
Income Tax Effects	2.5 [106]
2008 Cost Increase	**7.2**

Implementing the Company's employee future benefits proposals will require an increase of approximately 1.5 percent in revenue in 2008.[107]

3.7 REGULATORY DEFERRALS AND RESERVES

In this section of the Application, Newfoundland Power makes proposals concerning the:

(i) amortization of existing regulatory deferrals of revenue and costs;

(ii) amortization of certain existing regulatory reserve balances; and

(iii) amortization of third party costs relating to this Application.

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[104] Tax effects include a reduction in 2008 income tax of $2 million related to OPEBs and an increase in 2008 income tax of $0.5 million related to pension plans which all occur upon Newfoundland Power's adoption of the Tax Accrual Method for employee future benefits.

[105] Inclusion in rate base of the net accrued OPEBs liability will reduce both rate base and return on rate base in 2008. This is offset by the inclusion in rate base of the future tax asset related to the adoption of tax accrual accounting for employee future benefits. The rate base effects are reviewed in *Volume 2: Supporting Materials, Tab 4*.

[106] This is the income tax effects resulting from the adoption of accrual accounting for OPEBs and tax accrual accounting for employee future benefits. The income tax effects are reviewed in *Volume 2: Supporting Materials, Tab 4*.

[107] $7,200,000 (2008 cost increase) divided by $478,535,000 (existing 2008 forecast revenue) equals 1.5 percent.

The Company's proposals reflect a reasonable balance of the interests of the Company and its customers and are consistent with the principle of customer rate stability which is a primary basis of regulatory deferrals and reserves.

This section of the Application reviews the Company's current regulatory deferrals and reserves.

3.7.1 Regulatory Deferrals

The Company has a number of revenue deferrals and cost recovery deferrals (the "Regulatory Deferrals") related to Board Orders and accounting policy changes.[108] This Application is an appropriate proceeding in which to address the Regulatory Deferrals.

Table 33 shows the forecast Regulatory Deferrals as of December 31, 2007.

Table 33
Regulatory Deferrals
December 31, 2007
($000s)

Revenue Deferrals	
2005 Unbilled Revenue	16,446
Municipal Tax Liability	4,087
Total	**20,533**
Cost Recovery Deferrals	
Depreciation	11,586
Replacement Energy	1,147
Total	**12,733**

[108] See Order Nos. P.U. 40 (2005) and P.U. 39 (2006).

The largest of the Regulatory Deferrals is the 2005 Unbilled Revenue. It is a balance sheet accrual resulting from the Company's 2006 adoption of the accrual method of revenue recognition.[109]

Recognizing the municipal tax liability of approximately $4.1 million arises as a result of the Company's transition to the ARBM. It is a timing difference related to the recovery and payment of municipal taxes. Under the ARBM, the reconciliation of this timing difference results in a deduction from rate base.[110] From the perspective of the ARBM, the municipal tax liability is conceptually similar to the 2005 Unbilled Revenue.

For this reason, the Company is proposing to treat it in a similar manner as the 2005 Unbilled Revenue.[111]

The cost recovery deferrals include deferrals related to depreciation in 2006 and 2007 and replacement energy costs in 2007.

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[109] The 2005 Unbilled Revenue balance of $16.4 million, as at December 31, 2007, is determined as follows:

2005 Unbilled Revenue Balance at December 31, 2005	$23,631
Amortization of the Unbilled Revenue Increase Reserve	(295)
2006 Income Taxes related to the Tax Settlement	(3,086)
Weather Normalization Effects	(1,090)
2007 Income Taxes related to the Tax Settlement	(2,714)
2005 Unbilled Revenue Balance at December 31, 2007	$16,446

[110] Rate base treatment of the municipal tax liability is reviewed in *Section 3.4.1 Asset Rate Base Method*.

[111] Alternative potential regulatory treatments for the municipal tax liability are (i) to reflect it as a continuing reduction in rate base or (ii) to treat it as zero-cost capital. Both of these alternatives ensure that customers continue to receive the cash-flow benefits arising from the underlying timing differences in rates. Newfoundland Power has chosen to deal with the municipal tax liability in the same way as 2005 Unbilled Revenue to avoid long-term legacy adjustments to rate base or the weighted average cost of capital. Such adjustments will tend over the long-term to impair the regulatory transparency which underscores the transition to the ARBM.

The deferrals related to depreciation are approximately $5.8 million in each of 2006 and 2007. They effectively offset an increase in the Company's depreciation expense in those years attributable to the 2005 conclusion of the depreciation true-up.

The deferral related to the replacement energy cost is approximately $1.1 million. It effectively offsets an increase in the Company's 2007 power supply costs attributable to the refurbishment of the Rattling Brook hydroelectric plant.

In Order Nos. P.U. 40 (2005) and P.U. 39 (2006), which gave rise to the 2005 Unbilled Revenue and the cost recovery deferrals, the Board ordered that the recovery of these costs deferrals would be determined by a further Order of the Board.

As a result of the tax settlement negotiated in 2005, Newfoundland Power is required to pay an additional amount of income tax in 2006, 2007 and 2008 in respect of the 2005 Unbilled Revenue.[112] For 2008, it is appropriate that the additional amount of 2008 income tax of approximately $2.6 million[113] be deducted from the 2005 Unbilled Revenue.[114] After this final instalment of income tax is deducted, a balance of approximately $13.9 million[115] of the 2005 Unbilled Revenue will remain.

[112] In Order Nos. P.U. 40 (2005) and P.U. 39 (2006), the Board authorized Newfoundland Power to recognize an amount equal to the forecast taxes payable on account of the 2005 Unbilled Revenue for 2006 and 2007 respectively.

[113] $22,539,000 (2005 Unbilled Revenue) divided by 3 equals $7,513,000 (2005 Unbilled Revenue recognized for tax purposes in each of 2006, 2007 and 2008) multiplied by 34.5 percent (2008 tax rate) equals $2,591,985.

[114] Offsetting the increase in 2008 income tax recognition with an equivalent amount of 2005 Unbilled Revenue is least cost. Recovery of the increase in cash rates payable by customers would require the Company to pay additional tax on the increased amount of cash rates.

[115] $16,446,000 (2005 Unbilled Revenue as at December 31, 2007) minus $2,591,985 (2008 increased income tax) equals $13,854,015.

In this Application, Newfoundland Power is proposing a 5-year amortization of the Regulatory Deferrals. A 5-year amortization is consistent with regulatory practice.[116]

Table 34 shows the impact of a 5-year amortization of the Regulatory Deferrals on *pro forma* revenue requirements.

Table 34
Amortization of Regulatory Deferrals
***Pro forma* Revenue Requirement Impact[117]**
2008 to 2012
($000s)

	2008	**2009**	**2010**	**2011**	**2012**
Revenue Deferrals					
2005 Unbilled Revenue[118]	(8,188)	(4,230)	(4,230)	(4,230)	(4,230)
Municipal Tax Liability	(817)	(817)	(817)	(817)	(817)
Cost Recovery Deferrals					
Depreciation	3,538	3,538	3,538	3,538	3,538
Replacement Energy	359	359	359	359	359
Revenue Requirement Impacts	**(5,108)**	**(1,150)**	**(1,150)**	**(1,150)**	**(1,150)**

The 5-year amortization of Regulatory Deferrals will ***reduce*** *pro forma* revenue requirements by approximately $5.1 million in 2008 and $1.1 million thereafter.

[116] 5-year amortizations have been used for accumulated reserve variances identified in depreciation studies [see Order No. P.U. 7 (1996-97)], for material accounting policy changes such as those related to general expenses capital [see Order No. P.U. 3 (1995-96)] and for amortization of non-reversing weather normalization reserve balances [see Order No. P.U. 19 (2003)]. 3-year amortizations have been used for accumulated reserve variances identified in depreciation studies [(see Order No. P.U. 19 (2003)] and for third party general rate application costs [see Order Nos. P.U. 7 (1996-96), P.U. 36 (1998-99) and P.U. 19 (2003)].

[117] The *pro forma* revenue requirement effects of the 5-year amortization of the 2005 Unbilled Revenue and deferred costs related to depreciation include notional tax effects. That is, the impact on revenue requirements in 2008 is the sum of the amounts amortized and tax effects.
The Municipal Tax Liability is a cash flow timing difference which has not been recognized by the Company. Accordingly, the amortization impacts annual revenue requirements by the annual amount amortized in the year.
The *pro forma* revenue requirement effects of the 5-year amortization of the Replacement Energy costs will impact the 2008 revenue requirement by the amount amortized and notional tax effects. This reflects the fact that the deferred recovery of the replacement energy costs was approved on an *after-tax* basis.

[118] The 2005 Unbilled Revenue amortization in 2008 includes $2,592,000 related to the 2005 tax settlement and $2,771,000 related to the amortization of the 2005 Unbilled Revenue remaining balance over a 5-year period.

3.7.2 Regulatory Reserves

Regulatory reserves serve to provide a measure of stability for customers' rates. The Company has reviewed its regulatory reserve balances. This Application addresses current balances in the Company's Weather Normalization Reserve and Purchased Power Unit Cost Variance Reserve (the "Regulatory Reserves").

Weather Normalization Reserve

The Weather Normalization Reserve acts to stabilize electricity rates to customers by removing the volatility in the Company's sales and power supply cost related to hydrology (the "Hydro Component") and weather (the "Degree Day Component").[119] In theory, the balances in each component are expected to tend to zero over time.

In Order No. P.U. 19 (2003), the Board ordered that the Company review the balance in the Hydro Component and apply for an order to dispose of any non-reversing balances in its next general rate application.[120]

The Company's review of the Weather Normalization Reserve is found in *Volume 2: Supporting Materials, Tab 6*.

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[119] The Weather Normalization Reserve has two components: (i) a Hydro Production Equalization Reserve approved in Order No. P.U. 32 (1968) and, (ii) a Degree Day Normalization Reserve approved in Order No. P.U. 1 (1974).

[120] In Order No. P.U. 19 (2003), the Board approved amortization of the recovery of the $5.6 million non-reversing balance over 5 years commencing in 2003. A forecast 2007 year-end balance of $3.9 million in the Hydro Component is expected to diminish over time, if normal stream flows are experienced. Therefore, no action is required at this time with respect to the existing balance in the Hydro Component.

The Company's review of the Weather Normalization Reserve indicates that there is significant uncertainty as to whether the current $6.8 million owing from customers in the Degree Day Component will tend to zero over time.[121]

The current balance in the Degree Day Component is directly related to warmer than normal weather conditions experienced in the Company's service area over the past 5 years.

The fact that Newfoundland Power's marginal energy supply costs exceed marginal revenues will impact the operation of the Degree Day Component of the Weather Normalization Reserve.[122] The operation of the Degree Day Component is not expected to result in reversal of the existing balance unless weather continues to be *warmer* than normal over an extended period. This simply reflects that, as of January 1, 2007, Newfoundland Power's net contribution from sales[123] will increase with less sales (i.e., if weather is warmer than normal) and decrease with more sales (i.e., if weather is colder than normal). Prior to January 1, 2007, these dynamics were reversed.

Because of this change in circumstances, Newfoundland Power does not expect the $6.8 million balance in the Degree Day Component to reverse with normal long-term weather patterns.[124]

The Company is proposing to amortize recovery of the $6.8 million in the Degree Day Component over 5 years beginning in 2008.[125]

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[121] The $6.8 million effectively represents power supply costs which have been incurred but not recovered from customers as at December 31, 2006.

[122] A description of the energy supply cost dynamics is in *Section 3.8.1 Supply Cost Dynamics*.

[123] The Company's contribution from sales is the revenue less the cost of power purchased from Hydro.

[124] If weather conditions continue to be *warmer* than normal, then the current balance in the Degree Day Component will tend to reduce.

[125] This is consistent with the treatment of the non-reversing Hydro Component balance approved in Order No. P.U. 19 (2003).

Purchased Power Unit Cost Variance Reserve

In Order No. P.U. 35 (2005), the Board approved the Purchased Power Unit Cost Variance Reserve Account (the "Unit Cost Reserve").[126] The Unit Cost Reserve is a partial cost recovery reserve with a pre-determined range, or deadband, within which Newfoundland Power bears the risk of cost variations. The deadband provides the parameters for transfers to, or from, the Unit Cost Reserve.

Table 35 shows the operation of the Unit Cost Reserve for 2005 and 2006.

Table 35
Unit Cost Reserve
2005 to 2006
($000s)

	2005	**2006**
Unit Cost Variance	(439)	2,779
Deadband [127]	± 588	± 714
Variance[128]	-	2,065
Tax Effects[129]	-	(723)
Net Transfer To Reserve	**-**	**1,342**

In 2006, the transfer to the Unit Cost Reserve was approximately $1.3 million on an after-tax basis.[130] This balance reflects the after-tax benefit accruing to customers as a result of Newfoundland Power's customers' reduced demand requirements in 2006.

126 The creation of the Unit Cost Reserve was authorized by Order No. P.U. 44 (2004). Conceptually, through the use of unit costs, the reserve provides an incentive for the Company to influence demand conservation by its customers. Commencing in 2008, the Company is proposing that a substantially similar mechanism, called the Demand Management Incentive, replace the Unit Cost Reserve. The Demand Management Incentive is reviewed in *Section 2.3.3 Customer Relations*.

127 The deadband has been set to reflect 1 percent of test year billing demand. For 2005, it was $588,000 (10,545.55 kW times $4.65 times 12 months equals $588,441). For 2006 it was $714,000 (10,545.55 kW times $5.64 times 12 months equals $713,722).

128 This is the Unit Cost Variance less the deadband.

129 This reflects that Unit Cost Reserve transfers are on an *after-tax* basis. ($2,065,188 (Unit Cost Variance less deadband) times 35 percent (tax rate) equals $722,815.

130 Order No. P.U. 10 (2007) approved the deferral of consideration of the Unit Cost Reserve to this Application.

Newfoundland Power is proposing to amortize the balance in the Unit Cost Reserve over 5 years.

Impact of Reserve Proposals

Table 36 shows the impact of a 5-year amortization of a Regulatory Reserve balances on *pro forma* revenue requirements.

Table 36
Amortization of Regulatory Reserve Balances
***Pro forma* Revenue Requirement Impact**[131]
2008 to 2012
($000s)

	2008	**2009**	**2010**	**2011**	**2012**
Weather Normalization Reserve	2,076	2,076	2,076	2,076	2,076
Unit Cost Reserve	(413)	(413)	(413)	(413)	(413)
Revenue Requirement Impact	**1,663**	**1,663**	**1,663**	**1,663**	**1,663**

The 5-year amortization of Regulatory Reserve Balances will ***increase*** *pro forma* revenue requirements by approximately $1.7 million per year through 2012.

Since 2003, the Company has been amortizing $1.7 million per year for 5-years to recover the non-reversing balance in the Hydro Component of the Weather Normalization Reserve.[132] Accordingly, the amortization of the Regulatory Reserve Balances proposed in this Application effectively result in a continuation of regulatory reserve balance amortization recovered in current customer rates.

131 The *pro forma* revenue requirement effects of the 5-year amortization include notional tax effects. The amortization of Weather Normalization Reserve balance and the Unit Cost Reserve balance will impact *pro forma* revenue requirements by the amount amortized and notional tax effects. This reflects the fact that the amortization of both the reserve balances are on an *after-tax* basis.

132 This amortization was approved in Order No. P.U. 19 (2003). The $1.7 million includes tax effects related to amortization of Weather Normalization Reserve balances. See Table 16, *Section 3.2.2, Power Supply Cost*.

3.7.3 Application Costs

The Company estimates that approximately $1.2 million in costs will be incurred by the Board and the Consumer Advocate as a result of this Application.

Newfoundland Power is proposing that these costs be amortized evenly over a 3-year period commencing in 2008.[133]

3.8 REGULATORY POLICY

Supply cost dynamics on the Island interconnected grid have been changing due to increases in the price of fuel at Holyrood. These changes have implications for the regulation of Newfoundland Power.

In Order No. P.U. 19 (2003), the Board made a number of directives relating to Newfoundland Power's relationship with affiliated companies.

This section of the evidence reviews the changing supply cost dynamics on the Island interconnected grid and proposes modifications to the Rate Stabilization Account to address those dynamics. In addition, this section of the evidence reviews Newfoundland Power's response to the directives related to inter-corporate relationships made in Order No. P.U. 19 (2003).

[133] This is consistent with existing regulatory practice (see Order Nos. P.U. 7 (1996-97), P.U. 36 (1998-99) and P.U. 19 (2003).

3.8.1 Supply Cost Dynamics

Load requirements on the system increase annually, principally as a result of the addition of new customers. This increase in load requirements increases Newfoundland Power's supply costs from Hydro on a marginal basis. Recent changes in Hydro's wholesale rate have resulted in a dramatic increase in the cost to Newfoundland Power to supply increases in customer load ("Marginal Supply Cost"). The dramatic increase in the Marginal Supply Cost is the result of higher fuel costs related to production at Holyrood.[134]

It is the average test year cost of supply that is included in setting retail rates to Newfoundland Power's customers ("Average Supply Cost").[135]

Table 37 provides a comparison of Newfoundland Power's Average Supply Cost and Marginal Supply Cost from 2004 to 2008F.

Table 37
Cost of Electricity Supply
2004 to 2008F
(¢/kWh purchased)

	2004	**2005**	**2006**	**2007F**	**2008F**
Average Supply Cost	4.789	5.234	5.234	6.477	6.534
Marginal Supply Cost	4.789	5.974	6.245	9.901	9.901
Difference	**-**	**0.740**	**1.011**	**3.424**	**3.367**

The Marginal Supply Cost exceeds the Average Supply Cost by approximately 3.4¢ per kWh or approximately 50 percent for 2007 and 2008. The implication of current supply cost dynamics is

[134] This higher fuel cost is reflected in the Hydro's wholesale rate 2nd block energy charge.
[135] Average Supply Cost equals test year purchased power cost divided by test year purchases.

that Newfoundland Power's contribution from electricity sales will be eroded as a result of even modest increases in customer load requirements.[136]

Table 38 shows Newfoundland Power's marginal contribution per kWh of sales from 2004 to 2008F.

Table 38
Marginal Contribution[137]
2004 to 2008
(¢/kWh sold)

	2004	**2005**	**2006**	**2007**	**2008F**
Marginal Revenue[138]	7.9	8.1	8.2	9.3	9.8
Marginal Supply Cost of Sales[139]	5.1	6.3	6.6	10.5	10.5
Marginal Contribution	**2.8**	**1.8**	**1.6**	**(1.2)**	**(0.7)** [140]

A negative average marginal contribution exists for 2007 and is forecast to continue into 2008. This negative contribution demonstrates a systemic shortfall in supply cost recovery related to increases in customer load. This shortfall impairs Newfoundland Power's ability to recover not only its supply costs from Hydro but also its own costs of providing service.

For years beyond 2008, the supply cost recovery shortfall which currently exists can be expected to continue for so long as the current Marginal Supply Cost (i.e., predominantly Holyrood fuel costs) remains materially higher than the Average Supply Cost included in rates. To permit reasonable

136 Contribution is the net amount of revenue after deducting the cost of electricity supply payable to Hydro. Contribution, in effect, is the amount of revenue available to Newfoundland Power in any year to cover all of its cost of service, other than electricity supply costs.

137 Based on January prices and sales to new customers.

138 This is an estimate of the marginal revenue from new customers. Marginal revenue expressed in cents/kWh includes increased revenue that will occur from basic customer charges, energy charges and demand charges. The marginal revenue also assumes the usage patterns of new customers are the same as those of existing customers. The revenue excludes RSA and MTA impacts as these are flow-through items that do not affect revenue.

139 Includes energy losses. Due to energy losses within the distribution system, in order to sell 1 kWh of energy to customers, Newfoundland Power must purchase approximately 1.057 kWh of energy from Hydro.

140 The increase in 2008 marginal revenue from 9.3 ¢/kWh to 9.8 ¢/kWh includes the effect of the 5.3 percent proposed increase in current customer rates.

recovery of supply costs for periods beyond 2008, this situation would be expected to result in an increased frequency in rate cases for Newfoundland Power.

Existing regulatory mechanisms provide for Hydro's recovery of prudently incurred costs of fuel and for Newfoundland Power's customers payment of those costs. In this Application, Newfoundland Power is proposing changes to the Rate Stabilization Account which will permit recovery of supply costs related to the cost of production at the Holyrood.[141] The proposed mechanism will avoid additional regulatory proceedings driven principally by Newfoundland Power's need to recover prudently incurred supply costs.

An analysis of current supply cost dynamics on the Island interconnected grid is found in *Volume 2: Supporting Materials, Tab 7*.

3.8.2 Inter-Corporate Relationships

The Board has observed that utility transactions with related parties are unique due to their non-arms length nature. This gives rise to the principle that such transactions be fully transparent and subject to regulatory scrutiny.[142]

In Order No. P.U. 19 (2003), the Board specifically required the Company to (i) take the appropriate steps necessary to preserve its financial integrity and independence[143] and

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[141] The necessary changes to Newfoundland Power's Rate Stabilization Account to implement this proposal are reviewed in *Section 4.5.1 Energy Supply Cost Recovery in RSA.*

[142] This principle has been recognized by the Board in Order Nos. P.U. 6 (1991), P.U. 7 (1996-97) and P.U. 19 (2003).

[143] In Order No. P.U. 19 (2003), the Board concluded that in the interest of both the Company and its customers, Newfoundland Power should continue to be treated as a stand-alone utility. The Company was directed to take all appropriate steps necessary to preserve the financial integrity and independence of the Company (p. 39).

(ii) undertake certain operational measures and reviews relating to inter-corporate relationships.[144]

Financial Integrity

At the centre of the issue of the financial effect of inter-corporate relationships on Newfoundland Power, and potentially its customers, was the linkage made by Standard & Poor's between credit ratings of holding companies and credit ratings of their operating utilities.[145] By virtue of this linkage, any change to Standard & Poor's credit rating of Fortis Inc. would determine changes to Standard & Poor's credit rating of Newfoundland Power. This development raised the possibility that higher Newfoundland Power debt costs might result from actions taken by its unregulated parent.

In 2004, the Company completed a comprehensive review of its stand-alone credit status.[146] This review led to the Company entering into a $100 million dollar committed short-term credit facility in early 2005.[147]

In June 2005, an initial credit opinion of Newfoundland Power was issued by Moody's Investor Services. The opinion acknowledged Newfoundland Power's operational and financial independence.[148]

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[144] In Order No. P.U. 19 (2003), the Board observed that inter-corporate relationships had become more complex with the evidence indicating a continuing escalation, particularly as additional utilities are acquired by Fortis (p. 56).

[145] Standard & Poor's was the only credit rating agency to make such a linkage. The linkage is applied by Standard & Poor's to all Canadian utility holding company groups.

[146] This review was documented in *A Report on the Stand-Alone Credit of Newfoundland Power* filed on June 30, 2004 in compliance with Order No. P.U. 19 (2003).

[147] Committed credit facilities *oblige* lenders to provide credit so long as the terms of the facility are met by the borrower. In contrast, demand credit facilities do not obligate lenders to extend credit. The existence of committed credit facilities provides transparent assurance of Newfoundland Power's continued financial independence to interested parties. Entry into this credit facility by Newfoundland Power was authorized by Order No. P.U. 1 (2005).

[148] This development was reported to the Board in *A 2nd Supplementary Report on the Stand-Alone Credit of Newfoundland Power* filed on July 20, 2005. Moody's Investor Services does not rate the debt or credit of Fortis Inc., Newfoundland Power's holding company.

In August 2005, Newfoundland Power issued $60 million in 30-year First Mortgage Bonds at an interest rate of 5.441 percent.[149] This issue has the lowest interest rate of Newfoundland Power's outstanding First Mortgage Bonds. It was sold at a spread of 106 basis points (or 1.06 percent) over prevailing Long Canada Bond Yields.[150]

In June 2006, Newfoundland Power discontinued the use of Standard & Poor's as a rating agency for its First Mortgage Bonds.[151]

Currently, Newfoundland Power's First Mortgage Bonds are rated by Moody's Investors Service and Dominion Bond Rating Service. Both credit rating agencies assess Newfoundland Power to be operationally independent of Fortis Inc. and rate Newfoundland Power's credit as investment grade on a stand-alone basis.[152]

Since 2003, Newfoundland Power has taken all appropriate steps necessary to preserve its financial integrity and independence.

[149] This debt issue was authorized by Order No. P.U. 20 (2005).

[150] First Mortgage Bond issues are priced based upon a Long Canada Bond Yield plus an additional amount, or *spread*, to compensate debt holders for additional risk. The *spread* is dependent on many factors, including credit quality of the issuer and prevailing market conditions at the time of sale. By comparison, Newfoundland Power's previous two First Mortgage Bond issues had spreads of 130 basis points (in 1998) and 185 basis points (in 2002).

[151] From June 2005 to June 2006, Newfoundland Power's credit was rated by Dominion Bond Rating Service, Moody's Investors Services and Standard & Poor's. As only 2 credit ratings are required to maintain capital market access, Newfoundland Power discontinued use of Standard & Poor's services in 2006.

[152] The Company's current credit rating reports by DBRS and Moody's are found in Exhibit 6.

Operational Aspects

The directions contained in Order No. P.U. 19 (2003) were aimed at ensuring that Newfoundland Power's inter-corporate transactions were fully transparent and subject to regulatory scrutiny. The Company has complied with the directions.[153]

A reduction in the overall level of inter-corporate charges between Newfoundland Power and its affiliates has occurred since 2002.

Table 39 shows the total inter-corporate charges from Newfoundland Power to affiliated companies from 2002 to 2006.[154]

Table 39
Inter-corporate Charges to Affiliates
2002 to 2006
($000s)

	2002	**2003**	**2004**	**2005**	**2006**
Total Charges	4,962	4,081	3,418	1,386	1,321

In 2006, total inter-corporate charges from Newfoundland Power to its affiliated companies were approximately 27 percent of the total amount of inter-corporate charges in 2002.

[153] Details of the Company's response to the directions were reported in a *Report on Inter-Corporate Charges* filed on March 31, 2004 in compliance with Order No. P.U. 19 (2003). The Company's response included, amongst other things, (i) the implementation of interest charges (at a rate of prime plus 5 percent) for inter-corporate transactions not paid within 30 days of invoice and (ii) a mark-up of 20 percent on salary and benefit costs of senior management performing work for affiliates.

[154] In 2004, Fortis Inc. purchased two utilities, FortisBC Inc. and FortisAlberta Inc. The observation at p. 56 of Order No. P.U. 19 (2003) to the effect that '…the evidence appears to support a continuing escalation in inter-corporate charges, particularly as additional utilities are acquired by Fortis…' was a fair reflection of the evidence before the Board at that time. However, Newfoundland Power has taken the necessary steps to ensure that a continuing escalation in inter-corporate charges did not, in fact, result from Fortis' acquisition of additional utilities.

Recurring regulated charges to Newfoundland Power from affiliated companies has remained reasonably stable since 2002.

Table 40 shows the regulated charges from affiliated companies to Newfoundland Power from 2002 to 2006.[155]

Table 40
Regulated Charges from Affiliates
2002 to 2006
($000s)

	2002	**2003**	**2004**	**2005**	**2006**
Total Charges	260	464	250	307	1,014
Non-Recurring[156]		(228)	(34)	(26)	(50)
Joint Use Transfers[157]	(11)	(18)	(9)	(137)	(781)
Recurring Charges[158]	**249**	**218**	**207**	**144**	**183**

Newfoundland Power is required to demonstrate both the prudence and benefits associated with inter-corporate transactions. For insurance procurement, the economies of scale associated with the Fortis group insurance program actually reduce Newfoundland Power's insurance costs that are recovered in customer rates by approximately 25 percent.[159] While this is a prominent

[155] Regulated charges to Newfoundland Power from affiliated companies are part of the Company's cost of service which is recovered from its customers.

[156] In 2003 and 2004, non-recurring charges were related to a 2003 executive exchange which was made permanent in 2004. Similar charges were charged by Newfoundland Power to an affiliate in relation to this exchange. In 2005 and 2006, non-recurring charges related to a meter refurbishing contract with FortisAlberta Inc. The FortisAlberta Inc. meter contract was tendered to both affiliated and non-affiliated suppliers.

[157] Joint-use transfers from Fortis Inc. occur when utility poles owned by Fortis and carrying telecommunications circuits become used by Newfoundland Power to deliver electricity service. This arrangement was contemplated by Order No. P.U. 17 (2001-2002) which authorized Newfoundland Power's acquisition of Aliant Telecom Inc.'s utility poles. In 2005, the majority of transfers ($73,543) related to 2 lines built for joint-use prior to the acquisition authorized by Order No. P.U. 17 (2001-2002) but not actually put in joint use until 2005. In 2006, the majority of transfers ($726,025) related to lines associated with cabin areas at Howley, Boy Scout Road and Thorburn Lake. These lines were originally built for telecommunications circuitry pursuant to the CRTC authorized service improvement plan for Aliant Telecom Inc. The extension of electrical service to these cabin areas was approved by the Board pursuant to Order Nos. P.U. 17, 32 and 36 (2005).

[158] The primary component of recurring charges are related to costs associated with raising equity capital which were approved as justifiable inter-corporate charges in Order No. P.U. 7 (1996-97).

[159] The 2004 estimated Newfoundland Power cost of a stand-alone insurance program was approximately $1.9 million. Newfoundland Power's cost as a result of participation in the Fortis group insurance program in 2004 was approximately $1.5 million.

customer benefit arising from the Company's inter-corporate relationships all benefits associated with the Company's affiliate relationships will not necessarily be reflected in inter-corporate transactions reporting requirements.

For example, Newfoundland Power has been able to reduce costs through use of volume discounts available from pooling the Fortis' utilities buying power.[160] In 2006, Newfoundland Power and three affiliated Fortis utilities were able to negotiate an approximate 5 percent volume discount on polemount transformer requirements for 2007. Newfoundland Power expects to spend approximately $4.8 million on polemounted transformers in 2007.[161] While benefits yielded by pooling purchases will not always be readily observable, it is a fact of commerce that lower prices can often be obtained when quantities purchased are increased.[162]

Newfoundland Power observes the guidelines and principles of the Board with respect to inter-corporate transactions.

3.9 2008 REVENUE REQUIREMENTS

2008 revenue requirements are forecast to be approximately $508.7 million which are offset by revenue deferral amortizations of approximately $6.2 million.

The increase in revenue required in 2008 will result in an average increase in current customer rates of 5.3 percent.

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[160] Volume discounts negotiated with common suppliers for group purchasing does not constitute an inter-corporate transaction *per se* as there is no *transaction* between affiliates. Nevertheless, the ability to obtain such discounts related to group purchases will reduce costs and provide tangible benefits.

[161] The discount was 4.85 percent. This will result in capital expenditure savings of approximately $230,000 in 2007 ($4,750,000 times 4.85 percent equals $230,375).

[162] One of the difficulties in demonstrating the amount of volume discounts is that many suppliers are reluctant to show discounts on invoices. Some, such as Microsoft, however, do publicly disclose thresholds for volume discounts.

3.9.1 Summary of Revenue Requirements

The revenue requirements used to establish electrical rates is forecast to be $502.5 million in 2008.

Exhibit 9 presents the forecast 2008 revenue requirements.[163]

Table 41 shows a summary of the proposed 2008 revenue requirements including revenue requirement necessary to be recovered from rates.

Table 41
Summary of Proposed 2008 Revenue Requirements
($000s)

Power Supply Cost	327,709
Operating Expenses	47,890
Employee Future Benefits	9,718
Depreciation & Related Amortization	42,524
Income Taxes	22,357
Return on Rate Base	71,370
Other Adjustments[164]	92
	521,660
Deductions:	
Other Revenue	(12,011)
Non-Regulated Expenses (Net of Tax)	(983)
Proposed 2008 Revenue Requirement	**508,666**
Revenue Deferral Amortization	(6,180)
Proposed 2008 Revenue Requirements from Rates	**502,486**

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

[164] Composed of $62,000 related to the amortization of Capital Stock issue expenses and $30,000 related to interest on customer deposits.

3.9.2 Costs & Depreciation

Table 42 shows forecast 2008 power supply cost.

Table 42
2008 Power Supply Cost
($000s)

Existing	328,786
Amortizations	
Weather Normalization Reserve	2,076 [165]
Replacement Energy Cost	359 [166]
Unit Cost Reserve	(413) [167]
Impact of Elasticity	(3,099) [168]
Proposed	**327,709**

Table 43 shows forecast 2008 operating expenses.[169]

Table 43
2008 Operating Expenses (including OPEBs)
($000s)

Existing	48,723
Application Costs Amortization	(833) [170]
Increased OPEBs Costs	6,370 [171]
Pension and ERP Costs	3,348 [172]
Proposed	**57,608**

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[165] The amortization of the weather normalization reserve balance in power supply costs is consistent with the approach taken to amortize the Hydro Production Equalization balance of $5.6 million from 2003 through 2007 pursuant to Order No. P.U. 19 (2003). The Company's proposal regarding the amortization of the weather normalization reserve is reviewed in *Section 3.7.2 Regulatory Reserves*.

[166] The Company's proposal regarding the amortization of the replacement energy cost is reviewed in *Section 3.7.1 Regulatory Deferrals*.

[167] The Company's proposal regarding the amortization of the unit cost reserve is reviewed in *Section 3.7.2 Regulatory Reserves*.

[168] In Order No. P.U. 7 (1996-97), the Board directed Newfoundland Power to develop measures of price elasticity in conjunction with Hydro and build them into its forecasting methodology. In Order No. P.U. 36 (1998-99), the Board found that the economic assumptions underlying the Company's elasticity forecasts were reasonable. 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. 19 (2003). It is also consistent with the methodology currently used by Hydro.

[169] Exhibits 1 and 2 show the forecast operating costs for 2008 which are reviewed in detail in *Section 2 Customer Operations*.

[170] The Company's proposal regarding the amortization of the Application costs is reviewed in *Section 3.7.3 Application Costs*.

[171] The Company's proposals regarding OPEBs is reviewed in *Section 3.6.2 Pension Plans*.

[172] The Company's pension plan costs for 2008 is reviewed in *Section 3.6.2 Pension Plans*.

Table 44 shows forecast 2008 depreciation and related amortizations.

Table 44
2008 Depreciation Cost and Related Amortization
($000s)

Existing Depreciation	41,002
Proposed Depreciation Rates	(621)[173]
Amortization Reserve Variance	(174)[174]
Proposed Depreciation	**40,207**
Amortization of Cost Recovery Deferral	**2,317**[175]

Table 45 shows forecast 2008 income taxes.

Table 45
2008 Income Taxes
($000s)

Existing	14,256
Tax Effects of Application Proposals	8,101[176]
Proposed	**22,357**

[173] The Company's proposal regarding depreciation rates is reviewed in *Section 3.5.2 2008 Depreciation Expense*.
[174] The Company's proposal regarding the reserve variance is reviewed in S*ection 3.5.2 2008 Depreciation Expense*.
[175] The Company's proposal regarding the cost recovery deferral for depreciation is reviewed in *Section 3.7.1 Regulatory Deferrals*.
[176] The tax effects of the Application proposals are as follows:

	($000s)
Increase in Revenue Requirement, Exhibit 9	30,131
Amortization of 2005 Unbilled Revenue	(5,363)
Increase in Taxable Revenue	24,768
Reduction in Tax Deductible Expenses (purchased power, operating, interest)	2,446
Increase in Taxable Income	27,214
Tax Rate	(x 34.5%)
Increase in Cash Income Taxes	9,389
Decrease in Future Income Taxes	(1,288)
Increase in Total Income Taxes	8,101

3.9.3 Return on Rate Base

Exhibit 10 shows forecast 2008 return on rate base.

Table 46 summarizes the forecast 2008 return on rate base and rate of return on rate base.

Table 46
2008 Rate of Return on Rate Base
($000s)

Forecast Average Rate Base	809,291
Forecast Regulated Returns	
Debt	33,443
Preferred Equity	586
Common Equity	37,341
Return on Rate Base	71,370
Rate of Return on Rate Base (%)	**8.82**[177]

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

3.9.4 Deductions and Revenue Amortizations

Exhibit 9 shows forecast 2008 deductions from revenue requirements.

[177] The rate of return on rate base is calculated as ($71,370,000 divided by $809,291,000) equals 8.82 percent. The range of return on rate base proposed in this Application for 2008 is 8.64 to 9.00 percent based upon a 36 basis point range as approved by the Board in Order Nos. P.U. 36 (1998-99) and P.U. 19 (2003).

Table 47 shows forecast 2008 deductions from revenue requirements.

Table 47
2008 Proposed Deductions
($000s)

Other Revenue	12,011[178]
Non-Regulated Expenses	983[179]
Proposed	**12,994**

Table 48 shows forecast 2008 revenue deferral amortizations.

Table 48
2008 Proposed Amortizations
Revenue Deferrals
($000s)

2005 Unbilled Revenue	5,363[180]
Municipal Tax Liability	817[181]
Revenue Amortization	**6,180**

[178] $10,801,000 (existing other revenue) plus $1,200,000 (interest revenue) plus $30,000 (regulation changes; see *Section 4.5 Changes to the Rules and Regulations*) minus $20,000 (interest on rate stabilization account).

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

[180] The Company's proposals regarding 2005 Unbilled Revenue is reviewed in *Section 3.7.1 Regulatory Deferrals*.

[181] The Company's proposals regarding the municipal tax liability is reviewed in *Section 3.7.1 Regulatory Deferrals*.

3.9.5 Required Revenue Increase

Table 49 shows the forecast increase in revenue from rates of $26.6 million required to meet the Company's proposed 2008 revenue requirement.

Table 49
2008 Required Revenue Increase
($000s)

2008 Proposed Revenue Requirement	508,666
Revenue From Existing Rates	(478,535)
Amortization of Revenue Deferrals	(6,180)
Elasticity Impact	2,606 [182]
Required Increase in Revenue from Rates	**26,557**

The increase in revenue from rates for 2008 requires an average increase in current customer rates of 5.3 percent effective January 1, 2008.

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

SECTION 4: CUSTOMER RATES & REGULATIONS

4.1 OVERVIEW

An increase in customer rates is required to provide the proposed 2008 test year revenue requirement. Newfoundland Power's approach to changing customer rates is guided by generally accepted ratemaking principles.

The cost of service study establishes cost recovery by customer class. The cost of service study indicates that cost recovery from several of the General Service customer classes should be reduced. The Company is proposing to vary the rate increases by customer class to improve fairness in cost recovery among the customer classes.

Rate designs that reflect marginal costs promote efficiency. To encourage efficiency in electrical energy consumption, Newfoundland Power has taken marginal costs into account in designing its customer rates.

This section of the evidence reviews: the basis for the existing customer rates; the results of the embedded cost of service study and the marginal cost study and their implications for customer rates; and Newfoundland Power's rate change plan including rate design proposals. In addition, this section of the evidence outlines proposed changes to the Company's rules and regulations governing its provision of service.

4.2. RETAIL ELECTRICITY RATES

Newfoundland Power's retail rate structures are typical of those employed by most electric utilities in Canada.

Customer rates are designed based on generally accepted ratemaking principles. The Company's approach to rate design balances the need for prices to reasonably reflect a fair allocation of costs with the need to promote efficient use of electrical energy.

This section of evidence reviews: the 2008 customer, energy and demand forecast; existing Newfoundland Power customer rate designs; and the criteria used in establishing customer rates.

4.2.1 Customer, Energy and Demand Forecast

Newfoundland Power's 2008 customer, energy and demand forecast is found in *Volume 2: Supporting Materials, Tab 8*.

The Company's 2008 customer, energy and demand forecast reflects the impact of the proposals in this Application.[1] The forecast number of customers and their load requirements is a primary input used to determine revenue from customer rates.

[1] See Appendices B and C to the customer, energy and demand forecast (*Volume 2: Supporting Materials, Tab 8*).

Table 50 shows the Company's customer forecast for 2007 and 2008.

Table 50
Customer Forecast
2007 and 2008

	2007	**2008**
Domestic	200,609	202,453
General Service		
0-10 kW	11,911	11,901
10-100 kW (110 kVA)	8,376	8,486
110-1000 kVA	1,038	1,047
1000 kVA and Over	63	63
Total General Service	21,388	21,497
Street and Area Lighting	9,718	9,764
Total Customers	**231,715**	**233,714**

The number of customers is forecast to increase by approximately 0.9 percent between 2007 and 2008.

Table 51 shows the Company's energy sales forecast for 2007 and 2008.

Table 51
Energy Sales Forecast
2007 and 2008
(GWh)

	2007	**2008**
Domestic	3,013.0	3,048.5
General Service		
0-10 kW	93.8	94.6
10-100 kW (110 kVA)	626.4	636.7
110-1000 kVA	867.8	879.7
1000 kVA and Over	416.7	425.0
Total General Service	2,004.7	2,036.0
Street and Area Lighting	36.3	36.3
Total Energy Sales	**5,054.0**	**5,120.8**

Energy sales are forecast to increase by approximately 1.3 percent from 2007 to 2008.[2]

Table 52 shows the Company's forecast demand for 2007 and 2008.

Table 52
Demand Forecast
2007 and 2008
(MW)

	2007	**2008**
Native Peak[3]	1,211	1,224
Purchased[4]	1,093	1,106

Demand is forecast to increase by approximately 1.1 percent from 2007 to 2008. Total purchases from Hydro are forecast to increase by 1.2 percent from 2007 to 2008.

4.2.2 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 230,000 customers.[5]

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[2] This reflects 2008 elasticity effects of 32.9 GWh directly resulting from the proposed 2008 customer rate increase of 5.3 percent.

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

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

[5] Hydro serves approximately 23,000 rural customers on the Island interconnected grid. Hydro's rural customers 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.

Table 53 provides the percent of sales and customers by class.

Table 53
Newfoundland Power Customer Base
2008 Forecast

Rate	Class of Service	% of Total Customers	% of Total Energy Sales
1.1	Domestic	86.6	59.5
2.1	General Service 0-10 kW	5.1	1.9
2.2	General Service 10-100 kW (110 kVA)	3.6	12.4
2.3	General Service 110-1000 kVA	0.5	17.2
2.4	General Service 1000 kVA and Over	-[6]	8.3
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 percent of Newfoundland Power's annual energy sales are to domestic customers.

4.2.3 Rate Design Criteria

All aspects of Newfoundland Power's rate design, including the rate design proposals in this Application, are guided by the Criteria for Sound Rate Structure described by James Bonbright in *Principles of Public Utility Rates.*[7] These criteria are summarized as follows:

- *Practicality* – rates should be understandable, publicly acceptable and feasible in their application.
- *Effectiveness* – rates should yield total revenue requirements under the fair-return standard.

[6] The 63 customers in Rate 2.4 comprise less than 0.01% of total customers.
[7] Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, Chapter 16.

- *Stability* – rates should ensure revenue stability for the utility and also stability in the charges to customers.
- *Efficiency* – rates should discourage wasteful use of service and promote economic use of service.
- *Fairness* **–** rates should be fair in apportioning the total cost of service among customer classes and avoid undue discrimination.

The Company's continued use of these rate design criteria is consistent with past practice and with the rate design principles accepted by all parties in the negotiated settlement on cost of service and rate design at Hydro's 2006 general rate application.[8] Since these criteria often conflict with each other, rate design requires a balancing of the relevant criteria.

4.2.4 Customer Rate Designs

Newfoundland Power's customer rates include a Domestic rate and rates for different classes of General Service customers.[9] The Company's customer classes are typical of electric utilities where separate classes exist for Domestic and General Service customers.

The Domestic rate consists of a basic customer charge and a single energy charge that applies to all kilowatt-hour ("kWh") usage. Newfoundland Power's Domestic rate recovers demand costs and energy costs through a blended energy charge.

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[8] Attachment A of *Parties' Agreement on Cost of Service, Rate Design and Rate Stabilization Plan*, submitted to the Board on October 20, 2006 at the 2006 Hydro GRA.

[9] General Service customers include businesses, institutions and other end users that do not qualify for the Domestic rate. The General Service customer class designations are based on usage requirements (i.e., small, medium and large) to better reflect the different cost of serving each group. Also, street and area lighting rates are available for Domestic and General Service customers.

The recovery of demand costs through energy charges is common in Canadian electric utilities' domestic rates.[10]

General Service customers with monthly demands less than 10 kW are also served by a rate design that includes both a basic customer charge and a single energy charge. The recovery of demand costs through energy charges for small general service customers is a common practice among Canadian utilities.[11]

General Service customers with demands of 10 kW or greater are served by rate designs that include a basic customer charge, a demand charge and an energy charge, referred to as a demand and energy rate. The rate structures include energy block sizes that reflect individual customers' demand and energy requirements.[12] This type of rate structure is designed to promote efficiency by encouraging customers to improve their load factor.[13] A slightly higher demand rate is charged during the winter months to reflect the higher cost of demand during the winter season.[14]

The Company offers individual customers and municipalities a Street and Area Lighting Service that is based on the Company owning, installing and maintaining street and area lighting. The

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[10] Several Canadian utilities have an energy block structure in their domestic rate. Hydro Quebec has an inverted pricing structure (i.e., a higher price for the higher usage block). Manitoba Hydro, New Brunswick Power and Maritime Electric have declining block structures (i.e., a lower price for the higher usage block). Utilities in Alberta and Ontario have unbundled energy-only rates for domestic customers. Unbundled rates are characterized by itemized charges specific to the basis for the charge. For example, there can be one ¢/kWh charge for generation costs, a different ¢/kWh charge for transmission costs and another ¢/kWh charge for distribution costs.

[11] Utilities in all provinces have a block of energy available to small general service customers that is billed on an energy-only rate. The block size is based on demand for some utilities and energy for others.

[12] For General Service customers with demands of less than 1000 kVA (Rates 2.2 and 2.3), the energy block size varies in relation to the individual customer's demand. For General Service customers with demands of 1000 kVA and over (Rate 2.4), the energy block size is 100,000 kWh per month.

[13] Load factor relates a customer's average load to the customer's peak load. Higher load factor reflects a higher utilization of the capacity available within the power system.

[14] Winter months are December, January, February and March.

price for this service includes fixed monthly rates for lighting fixtures, poles (used exclusively for lighting) and underground servicing.

The Company also has a Curtailable Service Option available to General Service customers. The Curtailable Service Option provides for credits to be paid to those Rate 2.3 and Rate 2.4 customers that can reduce their demand, upon request, by between 300 kW and 5000 kW for short periods during the winter season. The Curtailable Service Option provides customers with an incentive to reduce their demand during peak periods.[15]

Detailed information of Newfoundland Power's current rate structures is provided in *Volume 2: Supporting Materials, Tab* 9.

4.3 COST OF SERVICE STANDARD

Recovery of the cost of service is generally accepted as a basic standard in assessing the reasonableness of a utility's rates.[16] The embedded cost of service study is used to assess fairness of cost recovery by customer class.

The load research study, an input to the embedded cost of service study, indicates that increased costs should be apportioned to the Domestic class and decreased costs apportioned to the General Service classes.

15 The 20 customers currently availing of the Curtailable Service Option provide approximately 8 MW of peak demand reduction.

16 Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, Basic Standard of Reasonableness, page 67.

Marginal costs are reflected in rate designs to promote efficient use of electrical energy. The marginal cost study indicates that: (i) the marginal costs on the system exceed the average costs recovered in customer rates and (ii) the marginal costs during the winter season are higher than the marginal costs during the rest of the year.

This section of evidence presents the results of the embedded and marginal cost of service studies which are used in developing Newfoundland Power's rate designs.

4.3.1 Embedded Cost of Service Study

Newfoundland Power assesses the fairness of its rates by comparing the cost to serve each class, as determined through an embedded cost of service study, with the revenue collected from that class ("revenue to cost ratio").[17] The Company uses revenue to cost ratios to assess whether cost recovery by class is reasonable.[18]

The Company has completed an embedded cost of service study for the purpose of assessing customer rates for the 2008 test year (the "Cost of Service Study"). The Cost of Service Study is based on 2005 results, but reflects current rates and the current depreciation study.

The Cost of Service Study is provided in *Volume 2: Supporting Materials, Tab 10.*

[17] There are two basic types of cost of service studies: embedded and marginal. The embedded cost of service study allocates the cost of providing service among customer classes based on the existing cost of utility plant and operating expenses. A marginal cost of service study estimates changes in costs resulting from changes in the quantity of customers and customers' load requirements.

[18] See the general discussion contained in Order No. P.U. 7 (1996-97) at pages 87 and 88.

Allocation of demand costs in an embedded cost of service study requires that estimates be made of the demand requirements of each customer class at peak times.[19] These estimates are generally obtained through load research. From December 2003 to March 2006, Newfoundland Power conducted a load research study to provide the required class demand estimates.[20]

A report on the 2006 Load Research Study is provided in *Volume 2: Supporting Materials, Tab 11*.

Table 54 provides comparative Cost of Service Study results using the new load research data and the data from the previous study.[21]

Table 54
Impact of Updated Load Research Data
Cost of Service Study

		Revenue to Cost Ratios (%)		
Class of Service	**Rate**	**Old Load Research**	**New Load Research**	**Change**
Domestic	1.1	97.6	93.7	(3.9)
General Service, 0-10 kW	2.1	106.8	119.8	13.0
General Service, 10-100 kW (110 kVA)	2.2	106.1	116.8	10.7
General Service, 110-1000 kVA	2.3	103.4	110.5	7.1
General Service, 1000 kVA and Over	2.4	100.4	103.9	3.5
Street and Area Lighting	4.1	102.4	101.5	(0.9)

The new class demand estimates have resulted in the revenue to cost ratios increasing for the General Service classes and decreasing for the Domestic class. This reflects an increase in the demand cost allocations to the Domestic class and a decrease in the demand cost allocations to

[19] Generation and transmission demand costs are allocated to customer classes in the Cost of Service Study based on each customer classes' contribution to the winter system peak. Distribution demand costs are allocated to customer classes based on the relative size of the class peak demand.

[20] The 2006 load research study provides statistically verifiable estimates of class demands at peak times. Load recorders, which store customer usage data by time interval throughout the day, were installed on 470 customer premises (with representation from each metered customer class). Data collected from the sample was extrapolated to estimate class demands.

[21] The Company's last load research study was conducted over the period 1992 to 1994.

the General Service classes. The change in the demand cost allocations is primarily due to (i) a change in the time of system peak[22], and (ii) new load estimates based on improved load research data.[23]

4.3.2 Marginal Cost Study

Conceptually, embedded cost of service studies look at what caused costs to be incurred while marginal cost of service studies look at what causes costs to change. Newfoundland Power promotes efficient use of electricity through rate design by reflecting marginal costs, as determined by a marginal cost study, in its customer rates.[24]

In January 2007, NERA Economic Consulting completed the *Newfoundland Power Marginal Cost of Electricity Study* (the "Marginal Cost Study"). The Marginal Cost Study includes both Hydro's marginal costs of generation and transmission and Newfoundland Power's marginal costs related to distribution and customer service.[25]

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22 During the 2003 to 2006 period, the system peak occurred in the early evening, whereas the system peak in the early 1990s occurred in the morning. The highest demand requirements for the Domestic customer class during the winter season typically occur in the early evening hours. Because the peak demand requirements for the Domestic class now coincide with the system peak, there has been an increase in the allocation of demand costs to the Domestic class in the Cost of Service Study. This reduces the revenue to cost ratio of the Domestic class. The highest demand requirements for the General Service customer classes during the winter season typically occur in the weekday morning hours. Because the peak demand requirements for the General Service customer classes no longer coincide with the system peak, the allocation of demand costs to those customer classes has decreased. This increases the revenue to costs ratios of the General Service classes.

23 Certain class demand estimates in the 1994 load research study were derived based on coincidence estimates, whereas all 2006 class demand estimates were derived from hourly load data.

24 In the Board's 1992 Report on Cost of Service, page 7, the Board stated that: ".. efficiency in the consumption of electric energy is important and should be encouraged to the extent possible.".

25 The report *Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission* completed by NERA was filed by Hydro in May 2006.

The Marginal Cost Study is provided in *Volume 2: Supporting Materials, Tab 12.*

Based on the results of the Marginal Cost Study the Company has observed that:

1. Marginal costs on the system exceed the average costs recovered in customer rates;
2. Practically all marginal generation demand, transmission demand, and distribution demand costs are related to winter season demand requirements; and
3. Marginal energy costs are substantially the same year-round.

4.4 RATE CHANGE PLAN

An average increase of 5.3 percent in current customer rates is required to provide the proposed 2008 test year revenue requirement.

The Cost of Service Study indicates that cost recovery from several of the General Service customer classes should be reduced. The Company proposes a gradual approach to bring all customer classes back within an acceptable cost recovery range.

The Marginal Cost Study indicates that retail energy charges should be increased to promote efficient use of electrical energy.

Newfoundland Power's rate design proposals provide a reasonable balancing of the criteria for sound rate structures.

This section provides the Company's rate design proposals to recover the increased revenue requirement for 2008 and to respond to the results of the Cost of Service Study and the Marginal Cost Study.

4.4.1 Embedded Cost Recovery

An increase in customer rates is required to provide the proposed 2008 revenue requirement.

Exhibit 11 provides the computation of the proposed 5.3 percent average increase in customer rates.

Newfoundland Power designs its customer rates to achieve revenue to cost ratios within the range of 90 percent to 110 percent.[26]

Table 55 shows the revenue to cost ratios from the Cost of Service Study.

Table 55
Cost of Service Study Results

Class of Service	Rate Code	Revenue to Cost Ratios %
Domestic	1.1	93.7
General Service, 0-10 kW	2.1	119.8
General Service, 10-100 kW (110 kVA)	2.2	116.8
General Service, 110-1000 kVA	2.3	110.5
General Service, 1000 kVA and Over	2.4	103.9
Street Lighting	4.1	101.5

The revenue to cost ratios for the General Service 0-10 kW and 10-100 kW (110 kVA) classes are materially greater than 110 percent, while the General Service 110-1000 kVA class is slightly above 110 percent. Rates should change to reduce the cost recovery for these classes.[27]

26 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%, …”.

27 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 percent, 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.

The Company proposes a gradual approach to bring all customer classes back within an acceptable cost recovery range.

Table 56 provides the 2008 proposed relative rate change by class and the resulting *pro forma* revenue to cost ratios.

Table 56
Proposed Relative Rate Changes by Class

Rate	Class	Relative to Average	*Pro forma* Revenue to Cost Ratios
1.1	Domestic	1% above[28]	94.6
2.1	General Service 0-10 kW	4% below	115.0
2.2	General Service 10-100 kW (110 kVA)	3% below	113.3
2.3	General Service 110-1000 kVA	1% below	109.4
2.4	General Service 1000 kVA and Over	Average	103.9
4.1	Street and Area Lighting	Average	101.5

4.4.2 Marginal Costs and Retail Rate Design

Marginal cost based rates provide price signals to customers that reflect the cost consequences of their electricity consumption decisions.

Newfoundland Power has incorporated marginal cost considerations in its rate designs proposed in this Application. The extent to which customer rates should be modified to better reflect marginal costs necessarily requires the exercise of judgement. For Domestic customers, Newfoundland Power is proposing to apply the increase to the energy charge to permit better reflection of current marginal energy costs. For General Service customers, a similar approach was taken in increasing the tail block energy charges. For General Service customer demand

[28] The Domestic class increase relative to average will vary slightly from 1 percent to ensure matching of revenue from rates to revenue requirement. The Domestic class is used to ensure matching since it is the largest class, and such reconciling adjustments will have the least impact on the Domestic class. In the rates filed with Newfoundland Power's May 10th, 2007 Application the relative Domestic class increase is, in fact, 1.08 percent higher than the overall average increase on account of this.

charges, the seasonal price differential was increased to better reflect seasonal marginal demand cost differences.

Newfoundland Power has not proposed structural changes to its rate designs in this Application. Time-based rate designs reflecting variances in marginal costs can charge customers different prices for consumption at different times of the year, on different days of the week or at different times of day. Time-based rate designs can be as simple as charging a higher price in the winter season, or as complex as charging several different prices throughout the day.

In theory, time-based rates promote energy efficiency by providing an incentive for customers to conserve energy in higher cost periods and use more energy in lower cost periods, or to shift their load from higher cost periods to lower cost periods. Designing rates to promote energy efficiency involves balancing the desire for rates to provide the right signals to customers with the need to have rates that customers can understand, and to which they can respond.[29] In modifying rate structures to promote energy efficiency, the cost impact on customers is another key policy consideration.[30]

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

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

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

4.4.3 Rate Design Proposals

Newfoundland Power conducted a rate review to determine what changes should be made to customer rates to recover the 2008 revenue requirement.

The rate design review completed by the Company is provided in *Volume 2: Supporting Materials, Tab 13*.

The following is a summary of the Company's rate design proposals resulting from the rate review.

- With the exception of Rate 2.1, energy charges should increase to better reflect the high marginal cost of energy on the system.
- With the exception of Rate 2.1, no increase is proposed in the Basic Customer Charges so as to accommodate higher percentage increases in energy charges to better reflect the high marginal cost of energy on the system.
- In Rate 2.1, where the current energy charge exceeds both the embedded and the marginal cost, the Company proposes to recover the class increase in revenue requirement through a higher Basic Customer Charge.
- The demand charges during the non-winter season should be reduced to increase the price differential between the winter and non-winter season and better reflect the seasonal cost differences on the system.
- The energy component of the maximum monthly charge in the General Service Rates 2.2, 2.3 and 2.4 should be increased to reflect the average increase in costs.
- The street and area lighting rates should continue to be developed based on recovering embedded costs with the price of fixtures, poles and wiring varying in a manner reflective of differences in their fixed costs and variable operating costs.

- The Curtailable Service Option provides operational and planning benefits and should be maintained. It is proposed that the annual credit remain at $29 per kVA and the value of curtailable load on the system continue to be monitored.

Individual rate components within each rate are proposed to change by different percentages, with tail block energy charges receiving the highest increases. Accordingly, customers within each class will experience percent bill impacts that vary according to usage.

The general impacts are as follows:

- Domestic customers with higher energy usage will receive higher percent rate increases.
- General Service customers served under Rate 2.1 will all experience approximately the same dollar increase.
- General Service customers served under Rates 2.2, 2.3 and 2.4 will experience percentage impacts that vary by load factor, with higher load factor customers (high energy use relative to billing demand) experiencing higher percentage increases. Low load factor customers served under Rates 2.2, 2.3 and 2.4 that are charged under the maximum monthly charge, will experience percentage increases approximately equal to the overall proposed average rate increase.

4.5 PROPOSED CHANGES TO THE RULES AND REGULATIONS

The Company is proposing changes to a number of regulations. These include:

- ***An addition to the Rate Stabilization Clause to provide reasonable recovery of energy supply costs;***

- ***A change in the requirement for payment in advance for temporary connections, special facilities and relocations; and***
- ***A change in the amount and application of the charge for rejected payments.***

This section provides the basis for the proposed changes.

4.5.1 Energy Supply Cost Recovery in RSA

Section 3.8.1 Supply Cost Dynamics of the evidence describes the need for a mechanism to ensure recovery of prudently incurred energy supply costs related to the cost of production at Holyrood. The current wholesale energy cost dynamics is such that Newfoundland Power's marginal energy supply cost is higher than the average energy supply cost included in customer rates. [31] As load grows, this results in a shortfall in recovery of energy supply costs. Similar to the operation of Hydro's RSP, which provides for recovery of prudently incurred costs of fuel, the Company proposes an addition to the Rate Stabilization Clause to address the shortfall.

The 2008 forecast average energy supply cost reflected in the Application is 5.467¢ per kWh.[32]

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[31] An analysis of the current supply cost dynamics is found in *Volume 2: Supporting Material*, *Tab 7*. Newfoundland Power's marginal energy supply cost is the 2nd block energy charge in Hydro's wholesale rate.

[32] Following is a summary of the 2008 forecast test year supply cost of purchases from Hydro.

2008 Forecast Supply Costs

	Forecast Costs ($000)	**Forecast Purchases (MWh)**	**Average Cost (¢ per kWh)**
Energy	273,198	4,996,800	5.467
Demand	52,489	4,996,800	1.050
Total	325,687	4,996,800	6.517

The 2008 forecast average supply cost is 6.517¢ per kWh. This amount is the sum of the average energy cost of 5.467¢ per kWh and the average demand cost of 1.050¢ per kWh.

The difference between the average energy supply cost and the marginal energy supply cost of 8.805¢ per kWh is the energy supply cost variance. It is proposed that an annual transfer be made to or from the Rate Stabilization Account reflecting the change in purchased power costs that result from the energy supply cost variance.

Table 57 provides an illustrative example of a year-end transfer to the RSA assuming a 1 percent increase in purchases above the test year forecast.[33]

Table 57
Example of Energy Supply Cost Variance
Transfer to RSA

Difference in energy costs		
Average Energy Supply Cost[34]	5.467	¢/kWh (A)
Wholesale rate 2nd Block price	8.805	¢/kWh (B)
Energy Supply Cost Variance	3.338	¢/kWh (C = B – A)
Difference in energy purchases from test year[35]	50,000,000	kWh (D)
Transfer (to) from reserve	$1,669,000	(C x D)/100

If energy purchases increase by approximately 1 percent above the test year forecast, the Company will incur approximately $1.7 million in additional purchased power costs that is not included in customer rates. The proposed RSA clause will allow the Company to recover this energy supply cost variance from customers. Conversely, if purchases reduce by 1 percent from test year, the $1.7 million energy supply cost variance will be returned to customers through the RSA.

[33] The 50 GWh amount represents approximately 1 percent of energy sales, which is slightly less than the average annual sales growth from 2002 to 2008F.

[34] The forecast test year cost of energy was determined by applying the wholesale energy rate effective January 1, 2007 to the 2008 forecast energy purchases.

[35] The change from test year will be determined based on weather normalized results to ensure no overlap with the operation of the weather normalization reserve.

Exhibit 12 presents the proposed addition to the Rate Stabilization Clause. The revised Rate Stabilization Clause also reflects some minor wording changes to improve clarity.[36]

4.5.2 Requirement for Payment in Advance

Regulations 9(b) and 9(c) require payment in advance for temporary connections, special facilities and relocations. The Company is proposing modifications Regulations 9(b) and 9(c) to allow the charges to be included on customer bills, subject to credit approval. This proposal provides increased customer convenience.

Exhibit 13 presents the existing and proposed Regulation 9(b) and 9(c).

4.5.3 Rejected Payment Fee

Regulation 10(d) permits the Company to apply a fee of $10.00 when a customer's cheque is returned due to non-sufficient funds ("NSF cheques"). This fee has been set at $10.00 since 1990. The fee offsets administration costs associated with NSF cheques, such as the cost of customer contacts and the cost of processing account adjustments.

[36] *Section II.* 1(ii) of the Rate Stabilization Clause presents the formula for computing the charges to the RSA related to recovering fuel costs incurred in operating the Company's thermal plants The formula contains a P variable which refers to the base rate paid to Hydro. Hydro's base rate contains two energy prices. The Company is proposing the variable definition for P be revised to clarify that it is the 2nd block of the rate paid to Hydro that is to be used in the computation.
Section II. 2 of the Rate Stabilization Clause provides for an annual year-end adjustment to the RSA to provide a matching of municipal taxes paid with municipal taxes collected through customer rates. The Company is proposing minor wording changes to improve the clarity of the provision.

The fee applies only to NSF cheques. It does not apply to other types of payment rejections by financial institutions, such as stopped payments and cheques rejected for reasons other than insufficient funds. The costs of handling these types of payment rejections are estimated to be the same as those related to NSF cheques. Many Canadian utilities apply a comparable fee to all returned payments.

The Company proposes that (i) the fee be increased to $16.00 to better reflect costs and (ii) to expand the application of the fee to include stopped payments and cheques rejected for reasons other than insufficient funds.

Exhibit 14, page 1 of 3, provides the basis for the proposed fee. The proposed fee is in the lower end of the range of fees charged by other utilities in Canada.

Exhibit 14, page 2 of 3, provides the results of a survey of Canadian utilities' fees for rejected payments.

Exhibit 14, page 3 of 3, provides the existing and proposed wording for Regulation 10(d).

Newfoundland Power Inc.

Operating Costs by Function
2002-2008
($000s)

	Function	**Actual 2002**	**Actual 2003**	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Forecast 2007**	**Forecast 2008**
1	Distribution	5,944	5,677	6,227	6,388	6,721	6,499	6,574
2	Transmission	597	645	814	490	486	661	750
3	Substations	2,265	2,550	2,939	2,442	2,530	2,494	2,495
4	Power Produced	2,174	2,383	2,822	2,646	2,688	2,511	2,516
5	Administrative & Engineering Support	7,833	6,518	6,723	5,926	5,315	5,466	5,580
6	Telecommunications	848	789	616	1,603	1,467	1,514	1,525
7	Environment	1,148	769	583	462	496	510	545
8	Fleet Operating & Maintenance	1,567	1,778	1,347	1,496	1,491	1,482	1,495
9	**Electricity Supply**	**22,376**	**21,109**	**22,071**	**21,453**	**21,194**	**21,137**	**21,480**
10	Customer Services	8,228	8,411	8,598	8,978	9,073	9,020	9,094
11	Uncollectible Bills	700	1,108	963	1,158	961	1,000	1,050
12	**Customer Services**	**8,928**	**9,519**	**9,561**	**10,136**	**10,034**	**10,020**	**10,144**
13	Information Systems	2,787	2,663	2,773	2,698	2,685	2,766	2,826
14	Financial Services	1,439	1,290	1,350	1,426	1,527	1,346	1,376
15	Corporate & Employee Services	12,176	13,536	11,837	11,745	11,557	12,102	11,972
16	Insurances	1,098	1,389	1,510	1,653	1,694	1,728	1,775
17	**General**	**17,500**	**18,878**	**17,470**	**17,522**	**17,463**	**17,942**	**17,949**
18	**Sub total**	**48,804**	**49,506**	**49,102**	**49,111**	**48,691**	**49,099**	**49,573**
19	Deferred Regulatory Costs	-	347	347	347	-	-	417
21	Pension & ERP Costs	3,972	3,787	4,345	6,369	7,343	5,513	3,348
22	**Gross Operating Expenses**	**52,776**	**53,640**	**53,794**	**55,827**	**56,034**	**54,612**	**53,338**
23	Transfer to GEC	(2,009)	(1,841)	(2,039)	(2,015)	(2,038)	(2,100)	(2,100)
24	**Net Operating Expenses**	**50,767**	**51,799**	**51,755**	**53,812**	**53,996**	**52,512**	**51,238**
	Number of Customers	219,072	221,653	224,464	227,301	229,500	231,715	233,714
	Gross Operating Cost per Customer ($)[1]	**223**	**225**	**220**	**218**	**212**	**212**	**214**

[1] Costs related to pensions and early retirement programs are excluded from the calculation of Gross Operating Cost per Customer.

Newfoundland Power Inc.

Operating Costs by Breakdown
2002-2008
($000s)

	Breakdown	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Forecast 2007	Forecast 2008
1	Regular and Standby	24,962	23,674	24,689	24,568	24,463	24,642	25,188
2	Temporary	1,545	1,723	2,097	2,232	2,204	2,127	2,040
3	Overtime	1,903	1,759	1,668	1,500	1,469	1,431	1,443
4	**Total Labour**	**28,410**	**27,156**	**28,454**	**28,300**	**28,136**	**28,200**	**28,671**
5	Vehicle Expenses	1,502	1,743	1,334	1,482	1,495	1,482	1,495
6	Operating Materials	1,564	1,486	1,555	1,432	1,232	1,137	1,124
7	Inter-Company Charges	626	769	667	489	575	560	568
8	Plants, Subs, System Oper & Bldgs	2,055	2,061	1,850	1,813	1,925	1,822	1,820
9	Travel	1,220	1,130	1,095	1,063	1,105	1,062	987
10	Tools and Clothing Allowance	799	1,000	962	899	822	835	836
11	Miscellaneous	1,635	1,654	1,684	1,463	1,421	1,457	1,486
13	Taxes and Assessments	823	866	784	660	253	680	680
14	Uncollectible Bills	700	1,108	963	1,158	961	1,000	1,050
15	Insurances	1,098	1,389	1,510	1,653	1,696	1,728	1,775
16	Retirement Allowances	59	336	233	48	218	175	175
17	Education, Training, Employee Fees	318	258	216	245	252	238	248
18	Trustee and Directors' Fees	339	406	375	388	373	386	395
19	Other Company Fees	1,909	2,187	1,434	1,697	1,605	1,609	1,418
20	Stationery & Copying	354	376	274	326	380	394	372
21	Equipment Rental/Maintenance	825	708	695	717	707	763	725
22	Telecommunications	1,511	1,598	1,626	1,694	1,656	1,620	1,630
23	Postage	1,294	1,364	1,406	1,506	1,537	1,465	1,571
24	Advertising	302	281	368	326	381	368	371
25	Vegetation Management	987	997	1,051	1,070	1,278	1,361	1,400
26	Computing Equipment & Software	474	633	566	682	683	758	776
27	**Total Other**	**20,394**	**22,350**	**20,648**	**20,811**	**20,555**	**20,899**	**20,902**
28	**Sub total**	**48,804**	**49,506**	**49,102**	**49,111**	**48,691**	**49,099**	**49,573**
29	Deferred Regulatory Costs	-	347	347	347	-	-	417
30	Pension Costs[1]	3,829	3,787	4,345	4,511	5,242	4,251	2,220
31	ERP (retirement allow & pension)	143	-	-	1,858	2,101	1,262	1,128
32	Other Employee Future Benefits	-	-	-	-	-	-	-
32	**Total Gross Operating Expenses**	**52,776**	**53,640**	**53,794**	**55,827**	**56,034**	**54,612**	**53,338**
33	Transfer to GEC	(2,009)	(1,841)	(2,039)	(2,015)	(2,038)	(2,100)	(2,100)
34	**Net Operating Expenses**	**50,767**	**51,799**	**51,755**	**53,812**	**53,996**	**52,512**	**51,238**

Newfoundland Power Inc.

Net Present Value Analysis of the 2005 Early Retirement Program
Pension Costs Funded Over 10 Years
Retirement Allowances Funded In 2005
Post-Retirement Analysis

	TOTAL COSTS						TOTAL BENEFITS										
		Pension Funding					Reduction In Salaries		Tax Deductions								
Year	Retirement Allowance A	Special Funding B	Current Service C	Tax Deductions D	Tax Savings E	Net After Tax Cost F	Capital G	Operating H	UCC Opening I	UCC Reductions J	UCC End Of Year K	CCA Reduction L	Operating Expense Reduction M	Total CCA/Expense Reduction N	Current Tax Increase O	Net After Tax Benefit P	**After Tax Cash Inflow (Outflow) Q**
2005[1]	(1,684,385)	(859,946)	381,901	(2,162,430)	781,070	(1,381,360)	1,065,878	1,495,226	-	1,065,878	1,011,305	54,573	1,495,226	1,549,799	(559,787)	2,001,317	**619,957**
2006	-	(1,146,594)	407,127	(739,467)	267,095	(472,372)	1,421,170	1,993,635	1,011,305	1,421,170	2,256,154	176,322	1,993,635	2,169,957	(783,788)	2,631,017	**2,158,646**
2007	-	(1,146,594)	433,959	(712,635)	257,404	(455,231)	1,421,170	1,993,635	2,256,154	1,421,170	3,373,530	303,794	1,993,635	2,297,429	(829,831)	2,584,974	**2,129,743**
2008	-	(1,146,594)	462,498	(684,096)	247,095	(437,001)	1,421,170	1,993,635	3,373,530	1,421,170	4,376,487	418,213	1,993,635	2,411,849	(871,160)	2,543,646	**2,106,645**
2009	-	(1,146,594)	492,849	(653,745)	236,133	(417,612)	1,421,170	1,993,635	4,376,487	1,421,170	5,276,741	520,916	1,993,635	2,514,551	(908,256)	2,506,550	**2,088,937**
2010	-	(1,146,594)	525,124	(621,470)	224,475	(396,995)	1,421,170	1,993,635	5,276,741	1,421,170	6,084,810	613,102	1,993,635	2,606,737	(941,554)	2,473,252	**2,076,257**
2011	-	(1,146,594)	559,445	(587,149)	212,078	(375,071)	1,421,170	1,993,635	6,084,810	1,421,170	6,810,132	695,848	1,993,635	2,689,484	(971,441)	2,443,364	**2,068,293**
2012	-	(1,146,594)	595,937	(550,657)	198,897	(351,760)	1,421,170	1,993,635	6,810,132	1,421,170	7,461,181	770,121	1,993,635	2,763,757	(998,269)	2,416,537	**2,064,777**
2013	-	(1,146,594)	634,737	(511,857)	184,883	(326,974)	1,421,170	1,993,635	7,461,181	1,421,170	8,045,562	836,789	1,993,635	2,830,424	(1,022,349)	2,392,456	**2,065,482**
2014	-	(1,146,594)	675,984	(470,610)	169,984	(300,626)	1,421,170	1,993,635	8,045,562	1,421,170	8,570,103	896,630	1,993,635	2,890,265	(1,043,964)	2,370,842	**2,070,216**
2015[2]	-	(286,649)	168,996	(117,653)	42,496	(75,156)	355,293	498,409	8,570,103	355,293	8,029,626	895,770	498,409	1,394,178	(503,577)	350,124	**274,968**
CCA End Effects												5,347,292		5,347,292	(1,931,442)	(1,931,442)	**(1,931,442)**
NPV at a Discount Rate of 6.07%.						$ (4,141,973)										$ 18,120,725	**$ 13,978,751**

Notes: A is the retirement allowances which are based on 20 weeks salary for retiring employees.
B is the actuarially determined funding requirements for the liability created by the 2005 early retirement program .
C is the reduction in current service funding requirements attributable to the 2005 early retirement program.
D is the tax deduction claimed as a result of the pension funding and retirement allowances. D = A+B+C.
E is D multiplied by the tax rate (absolute value). The income tax rate used is the statutory rate of 36.12%.
F is the net after-tax cost of the 2005 early retirement program. F = D + E.
G and H reflect the allocation of savings in salaries/pension costs to capital and operating. The allocation of salaries is based on an analysis of the capital/operating splits for each individual retiree.
I is the cumulative reduction in undepreciated capital cost (UCC) balance at the end of the previous year.
J is the reduction in UCC during the current year as a result of the capital reduction shown in G.
K is the cumulative reduction in the UCC balance at the end of the year. K = I + J - L.
L is the reduction in the current year CCA claim caused by the cumulative UCC reduction. It is based on an incremental CCA rate of approximately 10.24% with application of the CCA half-year rule.
It is calculated as L = ((I * 10.24%) + (J * 10.24% * 0.5))* -1
M is the reduction in operating expenses shown in H.
N is the total CCA and operating expense reduction. N = L + M.
O is the total increase in income tax caused by the reduction in tax deductible operating expenses and CCA. O = N * 36.12% * -1.
P is the net after-tax benefit of the 2005 early retirement program. P = G + H + O.
Q is the net after-tax cash impact of the 2005 early retirement program. Q = P + F.

[1] 9 months, April through December 2005.
[2] 3 months, January through March 2015.

Newfoundland Power Inc.

Demand Management Incentive Account

Proposed Definition

Demand Management Incentive Account 278xx

This account shall be charged or credited with the amount by which the Demand Supply Cost Variance exceeds the Demand Management Incentive. The Demand Management Incentive equals ±1% of test year wholesale demand charges.

The Demand Supply Cost Variance expressed in dollars shall be calculated as follows:

$$(A - B) \times C$$

Where:

A = actual demand supply cost in dollars per kWh determined by dividing the wholesale demand charges in the calendar year by the weather normalized kWh purchases for that year (as will be reported in Return 13 of Newfoundland Power's Annual Report to the Board).

B = test year demand supply cost in dollars per kWh determined by dividing the test year wholesale demand charges by the test year kWh purchases.

C = the weather normalized annual purchases in kWh.

The amount charged or credited to this account shall be adjusted for applicable income taxes calculated at the statutory income tax rate.

Disposition of any Balance in this Account
Newfoundland Power shall file an Application with the Board no later than the 1st day of March each year for the disposition of any balance in this account.

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Statements of Income
($000s)

		Historical Results						
							Forecast	Existing
		2002	2003	2004	2005	2006	2007	2008
1	Electricity Sales (GWh)	4,765	4,882	4,979	5,004	4,995	5,054	5,154
2								
3	Revenue From Rates	362,772	376,094	395,577	407,597	407,689	472,155	478,535
4	Amortization of the 2005 Unbilled Revenue	-	-	-	-	3,086	2,714	-
5		362,772	376,094	395,577	407,597	410,775	474,869	478,535
6								
7	Purchased Power Expense	210,764	226,232	242,280	254,222	255,425	322,688	328,786
8	Deferred Recovery of Replacement Energy Costs	-	-	-	-	-	(1,795)	-
9	Amortization of Weather Normalization Reserve	-	1,732	1,732	1,732	1,732	1,732	-
10		210,764	227,964	244,012	255,954	257,157	322,625	328,786
11								
12	Contribution	152,008	148,130	151,565	151,643	153,618	152,244	149,749
13								
14	Other Revenue	6,855	8,056	8,870	12,366	10,489	10,426	10,801
15								
16	Other Expenses:							
17	Operating Expenses	46,795	48,012	47,410	47,443	46,653	46,999	48,723
18	Pension and Early Retirement Costs	3,972	3,787	4,345	6,369	7,343	5,513	3,348
19	Cost Recovery Deferral	-	-	-	-	(5,793)	(5,793)	-
20	Depreciation	35,442	29,372	30,987	32,143	38,922	40,127	41,002
21	Finance Charges	26,853	30,009	30,393	31,369	32,677	33,790	32,775
22		113,062	111,180	113,135	117,324	119,802	120,636	125,848
23								
24	Income Before Income Taxes	45,801	45,006	47,300	46,685	44,305	42,034	34,702
25	Income Taxes	16,381	14,945	15,586	15,368	13,639	12,646	14,256
26								
27	Net Income	29,420	30,061	31,714	31,317	30,666	29,388	20,446
28	Dividends on Preference Shares	613	601	592	588	588	586	586
29								
30	Earnings Applicable to Common Shares	28,807	29,460	31,122	30,729	30,078	28,802	19,860
31								
32								
33	**Rate of Return and Credit Metrics**							
34	Return on Rate Base (percent)	9.94	9.03	8.82	8.53	8.57	8.12	6.64
35	Regulated Return on Common Equity (percent)	10.65	10.22	10.12	9.6	9.46	8.61	5.85
36	Interest Coverage (times)	2.6	2.4	2.5	2.4	2.3	2.2	2.0
37	Cash Flow Interest Coverage (times)	3.2	2.9	3.0	2.9	2.7	2.7	2.7
38	Cash Flow Debt Coverage (percent)	17.6	15.6	16.0	15.7	14.1	13.5	12.6

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Statements of Retained Earnings
($000s)

		Historical Results						
							Forecast	Existing
		2002	**2003**	**2004**	**2005**	2006	**2007**	**2008**
1	Balance - Beginning of Year	189,882	209,194	229,159	246,039	253,651	265,566	285,286
2	Net Income for the Period	29,420	30,061	31,714	31,317	30,666	29,388	20,446
3		219,302	239,255	260,873	277,356	284,317	294,954	305,732
4								
5	Dividends							
6	Preference Shares	613	601	592	588	588	586	586
7	Common Shares	9,495	9,495	14,242	23,117	18,163	9,082	18,989
8		10,108	10,096	14,834	23,705	18,751	9,668	19,575
9								
10	Balance - End of Year	209,194	229,159	246,039	253,651	265,566	285,286	286,157

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Balance Sheets
($000s)

	Historical Results						
						Forecast	Existing
	2002	2003	2004	2005	2006	2007	2008
Assets							
Fixed Assets							
Property, plant & equipment	1,010,704	1,070,674	1,113,519	1,149,582	1,187,535	1,233,718	1,270,976
Less: accumulated amortization	421,929	448,245	462,947	476,932	494,856	516,933	541,229
Less: Contributions in aid of Construction	20,300	20,300	20,495	21,192	23,142	23,350	23,464
	568,475	602,129	630,077	651,458	669,537	693,435	706,283
Current Assets							
Cash	2,485	-	467	-	-	-	-
Accounts receivable	55,275	55,844	59,571	58,730	61,604	73,025	73,735
Materials and supplies	4,525	5,250	5,419	5,206	4,923	5,400	5,500
Prepaid Expenses	1,169	1,240	1,292	1,211	1,222	1,222	1,222
Rate stabilization account	5,751	6,497	8,763	9,284	10,793	12,711	12,711
	69,205	68,831	75,512	74,431	78,542	92,358	93,168
Corporate Income Tax Deposit	6,949	6,949	6,949	-	-	-	-
Deferred and other charges	70,291	78,282	84,082	90,128	95,201	102,012	104,812
Regulatory Assets	10,919	11,499	11,195	11,066	17,735	23,416	23,416
OPEB Asset	10,013	13,684	17,495	22,976	27,782	34,102	40,374
	735,852	781,374	825,310	850,059	888,797	945,323	968,053
Shareholder's Equity and Liabilities							
Shareholder's Equity							
Common shares	70,321	70,321	70,321	70,321	70,321	70,321	70,321
Retained earnings	209,194	229,159	246,039	253,651	265,566	285,286	286,157
Common shareholder's equity	279,515	299,480	316,360	323,972	335,887	355,607	356,478
Preference shares	9,709	9,429	9,417	9,410	9,353	9,353	9,353
	289,224	308,909	325,777	333,382	345,240	364,960	365,831
Current Liabilities							
Bank indebtedness	-	1,278	-	772	400	-	-
Accounts payable and accrued charges	51,965	48,678	56,868	58,493	65,310	69,415	71,302
Current portion of long-term debt	3,650	3,650	3,650	4,250	35,720	4,450	4,450
Municipal tax liability	9,218	9,535	10,187	10,966	11,328	11,328	11,328
	64,833	63,141	70,705	74,481	112,758	85,193	87,080
Future income taxes	-	988	1,501	1,375	-	-	419
Short-term borrowings	15,987	39,909	58,109	11,040	34,751	40,359	57,878
Long-term debt	332,208	328,558	324,908	380,058	344,338	399,288	394,838
Other Liabilities	2,346	2,870	3,065	3,116	3,426	3,633	3,845
Regulatory Liabilities	21,241	23,315	23,750	23,631	20,502	17,788	17,788
OPEB Liability	10,013	13,684	17,495	22,976	27,782	34,102	40,374
	735,852	781,374	825,310	850,059	888,797	945,323	968,053

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Statements of Cash Flows
($000s)

		Historical Results					Forecast	Existing
		2002	2003	2004	2005	2006	2007	2008
1	**Cash From (Used In) Operating Activities**							
2	Net Income	29,420	30,061	31,714	31,317	30,666	29,388	20,446
3								
4	Amortization of capital assets	35,442	29,372	30,987	32,143	38,922	40,126	41,002
5	Amortization of deferred charges	436	186	268	353	313	324	308
6	Amortization of regulatory assets and liabilities	(1,019)	484	300	1,812	(5,349)	(1,455)	-
7	Regulatory deferrals	-	(693)	(3,472)	(1,683)	(4,451)	(6,940)	-
8	Future income taxes	-	988	513	(126)	(1,375)	-	419
9	Accrued employee future benefits	(9,148)	(7,753)	(2,246)	(5,814)	(4,745)	(6,327)	(2,896)
10	Change in non-cash working capital	5,783	(3,253)	2,728	9,848	3,070	(9,714)	1,078
11		60,914	49,392	60,792	67,850	57,051	45,402	60,357
12								
13	**Cash From (Used In) Financing Activities**							
14	Net Proceeds from long-term debt	74,325	-	-	60,000	-	59,400	-
15	Repayment of long-term debt	(2,900)	(3,650)	(3,650)	(4,250)	(4,250)	(36,320)	(4,450)
16	Short-term borrowings	(59,122)	23,922	18,200	(47,069)	23,711	5,608	17,519
17	Contributions from customers and security deposits	1,027	1,788	1,411	1,749	3,166	1,500	1,500
18	Redemption of preference shares	-	(280)	(12)	(7)	(57)	-	-
19	Dividends							
20	Preference Shares	(613)	(601)	(592)	(588)	(588)	(586)	(586)
21	Common Shares	(9,495)	(9,495)	(14,242)	(23,117)	(18,163)	(9,082)	(18,989)
22		3,222	11,684	1,115	(13,282)	3,819	20,520	(5,006)
23								
24								
25	**Cash From (Used In) Investing Activities**							
26	Capital expenditures (net of salvage)	(59,868)	(64,749)	(60,315)	(55,399)	(60,235)	(65,522)	(55,351)
27	Other deferred charges	-	-	-	(465)	(59)	-	-
28	Long-term portion of finance programs	(1,643)	(90)	153	57	(204)	-	-
29		(61,511)	(64,839)	(60,162)	(55,807)	(60,498)	(65,522)	(55,351)
30								
31	**Increase (Decrease) in Cash**	2,625	(3,763)	1,745	(1,239)	372	400	-
32	**(Bank Indebtedness) Cash, Beginning of Period**	(140)	2,485	(1,278)	467	(772)	(400)	-
33	**(Bank Indebtedness) Cash, End of Period**	2,485	(1,278)	467	(772)	(400)	-	-

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Average Rate Base[1]
($000s)

		Historical Results					Forecast	Existing
		2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
1	Plant Investment	991,114	1,039,836	1,092,096	1,131,554	1,168,561	1,210,625	1,252,347
2								
3	Add:							
4	Deferred Charges	-	72,937	80,046	86,063	91,441	96,945	101,684
5	Weather Normalization Reserve	10,409	10,677	10,456	10,289	10,954	11,246	10,683
6	Deferred Energy Replacement Costs	-	-	-	-	-	574	1,147
7	Cost Recovery Deferral	-	-	-	-	2,897	8,690	11,586
8	Future Income Taxes	-	(494)	(1,245)	(1,438)	(688)	-	(210)
9	Customer Finance Programs	558	613	608	572	791	901	800
10		10,967	83,733	89,865	95,486	105,395	118,356	125,690
11								
12	Deduct:							
13	Accumulated Depreciation	414,451	434,491	455,595	469,942	485,894	505,892	529,081
14	Work In Progress	2,630	2,290	786	644	943	1,716	2,314
15	Contributions In Aid of Construction	19,887	20,044	20,398	20,844	22,167	23,246	23,407
16	2005 Unbilled Revenue	-	-	-	-	21,396	17,803	16,446
17	Unit Cost Reserve	-	-	-	-	671	1,342	1,342
18		436,968	456,825	476,779	491,430	531,071	549,999	572,590
19								
20	Average Rate Base Before Allowances	565,113	666,744	705,182	735,610	742,885	778,982	805,447
21								
22	Cash Working Capital Allowance	4,712	4,977	5,268	5,514	5,522	6,576	6,672
23								
24	Materials and Supplies Allowance	3,512	4,009	4,661	4,322	4,510	4,217	4,453
25								
26	Average Rate Base At Year End	573,337	675,730	715,111	745,446	752,917	789,775	816,572

[1] All numbers shown are averages.

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Average Capital Structure
($000s)

		Historical Results					Forecast	Existing
		2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
1	**Average Capital Structure**							
2	Debt	345,426	362,620	380,031	391,394	405,665	429,653	450,632
3	Preference Shares	9,709	9,569	9,423	10,614	9,382	9,353	9,353
4	Common Equity	277,119	297,590	316,973	328,922	329,930	345,748	356,043
5		632,254	669,779	706,427	730,930	744,977	784,754	816,028
6								
7	Debt	54.63%	54.14%	53.80%	53.55%	54.45%	54.75%	55.22%
8	Preference Shares	1.54%	1.43%	1.33%	1.45%	1.26%	1.19%	1.15%
9	Common Equity	43.83%	44.43%	44.87%	45.00%	44.29%	44.06%	43.63%
10		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11								
12								
13	**Regulated Cost of Capital**							
14	Debt	7.88%	8.38%	8.06%	8.07%	8.14%	7.94%	7.33%
15	Preference Shares	6.31%	6.28%	6.28%	6.25%	6.27%	6.27%	6.27%
16	Common Equity	10.65%	10.22%	10.12%	9.60%	9.46%	8.61%	5.85%
17								
18								
19	**Weighted Average Cost of Capital**							
20	Debt	4.30%	4.54%	4.34%	4.32%	4.43%	4.35%	4.05%
21	Preference Shares	0.10%	0.09%	0.08%	0.09%	0.08%	0.07%	0.07%
22	Common Equity	4.67%	4.54%	4.54%	4.32%	4.19%	3.79%	2.55%
23		9.07%	9.17%	8.96%	8.73%	8.70%	8.21%	6.67%

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Rate of Return on Rate Base
($000s)

		Historical Results						
							Forecast	Existing
		2002	2003	2004	2005	2006	2007	2008
1	Regulated Return on Common Equity	29,518	30,415	32,088	31,644	31,227	29,777	20,843
2	Return on Preferred Equity	613	601	592	588	588	586	586
3		30,131	31,016	32,680	32,232	31,815	30,363	21,429
4								
5	Finance Charges							
6	Interest on Long-term Debt	26,094	30,501	30,165	31,046	32,759	33,564	31,513
7	Other Interest	1,846	762	1,277	1,535	1,309	1,582	2,562
8	Interest Earned	(872)	(1,063)	(979)	(1,158)	(1,210)	(420)	(350)
9	Interest Charged to Construction	(454)	(471)	(335)	(319)	(436)	(1,200)	(1,200)
10	Amortization of Bond Issue Expenses	167	198	199	201	193	188	188
11	Amortization of Capital Stock Issue Expenses	72	82	66	64	62	62	62
12		26,853	30,009	30,393	31,369	32,677	33,776	32,775
13								
14	Return on Rate Base	56,984	61,025	63,073	63,601	64,492	64,139	54,204
15								
16	Average Rate Base	573,337	675,730	715,111	745,446	752,917	789,775	816,572
17								
18	Rate of Return on Rate Base	9.94%	9.03%	8.82%	8.53%	8.57%	8.12%	6.64%

Newfoundland Power Inc.

Financial Performance
2002 - 2008
Major Inputs and Assumptions for 2007 and 2008 Forecasts

Forecast results for 2007 and 2008 are based on electricity rates effective January 1, 2007 approved by the Board in Order No. P.U. 8 (2007) and before implementation of any of the proposals in this Application. Specific assumptions include:

Energy Forecasts :	Energy forecasts are based on economic indicators taken from the Conference Board of Canada forecast dated December 19, 2006.
Revenue Forecast :	The revenue forecast is based on the Customer, Energy and Demand forecast filed in this Application.
	Revenue for 2007 includes the amortization of $2.7 million of the 2005 unbilled revenue as approved in Order No. P.U. 39 (2006).
Purchased Power Expense :	Rates charged by Newfoundland and Labrador Hydro approved by the Board in Order No. P.U. 8 (2007).
	Purchased Power Expense for 2007 includes a $1.7 million amortization of the Hydro Equalization Reserve as approved in Order No. P.U. 19 (2003).
	Purchased Power Expense for 2007 has been reduced to reflect deferred replacement energy costs of $1.8 million ($1.1 million after tax) as approved in Order No. P.U. 39 (2006).
Pensions and Early Retirement 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, 2005 filed with this Application and a Board approved schedule of funding payments.
	Pension expense discount rate is assumed to be 5.25% in 2007 and 2008.
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.
Depreciation Rates :	Depreciation rates for 2007 and 2008 are based on the 2002 depreciation study as approved by the Board in Order No. P.U. 19 (2003).
Short-Term Interest Rates :	Average short-term interest rates are assumed to be 4.91% in 2007 and 5.00% in 2008.
Long-Term Debt :	A $60.0 million long-term debt issue is forecast to be completed on August 1, 2007. The debt is forecast for 30 years at a coupon rate of 5.50 %. 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 36.12 % in 2007 and 34.5% in 2008.
	Income tax expense includes $2.7 million in 2007 and $2.6 million in 2008 related to the 2005 tax settlement.

Credit Rating Reports
DBRS and Moody's

Rating Report

Report Date: March 9, 2007
Press Release: February 26, 2007
Previous Report: January 6, 2006

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DBRS
Insight beyond the rating.

Newfoundland Power Inc.

Rating

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

Rating History	Current	2006	2005	2004	2003	2002	2001
First Mortgage Bonds	A	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable.	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Rating Update

DBRS has confirmed the ratings of Newfoundland Power Inc. (Newfoundland Power or the Company) as listed above, with Stable trends. The ratings continue to be supported by the consistent operating results and financial profile of the Company, which is largely due to a supportive regulatory environment

The Company benefits from the following features: (1) A favourable deemed equity ratio of 45%. (2) A weather normalization account that is used to stabilize earnings during extreme weather conditions. (3) A rate stabilization account that was established to absorb fluctuations between the estimated and actual cost of fuel oil for the Company's primary electricity supplier. These features combine to contribute to the Company's favourable financial profile.

EBIT increased slightly as a result of accounting accruals and deferrals. During 2006, the Company recognized $3.1 million in 2005 unbilled revenue and a $5.8 million deferred recovery of capital asset amortization.

Capital expenditures in 2006 were up modestly from 2005 as the Company continued to invest in upgrading the reliability and efficiency of its facilities and are expected to be approximately $62 million for 2007. As a result, modest free cash flow deficits are expected to continue in the near term. DBRS expects the Company to continue funding these shortfalls with borrowings under its credit facilities, to be refinanced with the issuance of first mortgage bonds, as well as by managing the level of dividends, in order to maintain a long-term capital structure of 55% debt and 45% equity, as deemed by the regulator. The Company's regulatory-approved ROE remains sensitive to changes in interest rates, as it is based on average long-term Government of Canada bond yields, adjusted annually. As a result, allowable returns have declined in recent years, with the approved ROE for 2007 declining to 8.60%, versus 9.24% in 2006, which will modestly impact earnings and cash flow. Additionally, an important challenge for the Company remains managing the Demand Energy Rate (DER). The Company intends on filing a General Rate Application (GRA) with the PUB in 2007 for the purpose of setting customer rates for 2008. (Continued on page 2.)

Rating Considerations

Strengths

- Supportive regulatory environment
- Strong balance sheet and favourable financial profile
- Stable customer base
- Limited competition from alternative fuels

Challenges

- Reliance on Newfoundland and Labrador Hydro for majority of power supply
- Allowed returns are sensitive to interest rates
- Managing forecast risk
- Limited growth potential

Financial Information

	For the 12-month period ended				
($ millions)	Dec. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec. 2002
EBIT	77.0	76.0	77.7	75.1	72.6
Free cash flow	(18.8)	(10.9)	(12.9)	(23.6)	(0.4)
Total debt in the capital structure (1)	55.0%	54.7%	54.7%	55.1%	55.3%
Cash flow/total debt (1)	12.9%	14.2%	14.9%	14.0%	18.1%
Fixed-charges coverage (times)	2.20	2.27	2.40	2.33	2.51
Dividend payout ratio	60.4%	78.8%	45.7%	32.2%	33.0%

(1) Total debt adjusted for preferred shares.

The Company

Newfoundland Power generates, transmits and distributes electricity to approximately 229,000 customers throughout the island portion of Newfoundland. The Company purchases over 90% of its electricity needs from government-owned Newfoundland and Labrador Hydro (NLH) and generates the balance from owned generation facilities (approximately 136 MW). Fortis Inc. (Fortis) owns all of the common shares of Newfoundland Power.

RATING UPDATE (Continued from page 1.)

Key cash flow and coverage ratios have modestly trended downward in recent years; however, they are expected to remain stable or improve over the medium term, depending upon the outcome of a 2008 GRA. DBRS expects these ratios to remain within a range that is consistent with the current ratings.

While Newfoundland Power operates independently of its parent, Fortis, DBRS notes that on February 26, 2007, Fortis announced its intention to acquire 100% of the common shares of Terasen Inc. (Terasen) from Kinder Morgan, Inc. for total consideration of approximately $3.7 billion, including $2.3 billion in assumed debt. The acquisition only includes Terasen's natural gas distribution businesses. DBRS believes that the transaction should not impact Newfoundland Power. DBRS confirmed Newfoundland Power's ratings shortly after the acquisition announcement.

RATING CONSIDERATIONS

Strengths

- Newfoundland Power operates in a supportive regulatory environment, which is based on a cost-of-service methodology. The PUB allows for the pass through of purchased power costs, and in addition, a rate stabilization account is in place in order to absorb fluctuations between estimated and actual costs of fuel oil used to generate electricity by NLH.
- The Company also has a weather normalization reserve account (WNR), approved by the PUB, to adjust for variances in weather and stream flow when measured against long-term averages. This provides Newfoundland Power with a mechanism to stabilize earnings, particularly during periods of abnormal weather conditions. The WNR and the underlying calculations are reviewed annually by the PUB.
- The Company has a strong balance sheet with a capital structure based on the approved 45% equity allowed by the regulator. The Company's financial profile is strong with relatively minor free cash flow deficits as the Company invests to upgrade its infrastructure. Key credit ratios have modestly trended downward in recent years; however, remaining in line with the current rating category. 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.
- Newfoundland Power also has a very stable customer base, as 100% of power sales are 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 90% of new home construction installed electric heat in 2006.
- The lack of availability of natural gas, due to geographic isolation and lack of related infrastructure, also limits competitive pressures. Over 50% of the Company's current customers utilize electric space heating, causing electricity sales to be much higher during the winter than in the summer.

Challenges

- Newfoundland Power relies heavily on NLH for its power supply, purchasing over 90% of its power requirements. The cost of power from NLH is influenced by the market price of Bunker C fuel oil, due to that company's significant amount of oil-fired generation capacity. Any increase in the price of oil is accumulated by NLH into a rate stabilization account and recovered over a one-year period through rate increases to Newfoundland Power. While increases in purchased power rates are passed directly on to Newfoundland Power's customers, higher rates may lead to energy conservation by customers, which could negatively impact 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.
- Under the current regulatory regime, earnings are sensitive to interest rates as the approved ROE is 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 approved ROE for 2007 declined to 8.60%, compared with 9.24% in 2006, as calculated by the automatic adjustment formula, which DBRS estimates will negatively impact after-tax earnings by approximately $1.6 million.
- The key challenge with respect to the DER will be the Company's ability to accurately and consistently forecast electricity demand going forward. However, the maximum pre-

tax loss in the event that actual demand is greater than forecasted, is currently limited to a threshold amount of +/-$521,000 for 2007, subject to final PUB approval (+/-$714,000 for 2006). Amounts in excess of this threshold are charged/rebated to customers, in a manner to be determined by the PUB. (See Regulation section for more information on the DER).

- The Newfoundland economy is heavily dependant on more volatile natural resource sectors. Over the medium term, natural resource development will continue to have a major impact on economic growth, with 2007 overall growth projected to be 5.7% by the Conference Board. However, service sector growth, which is the primary influence on sales growth for the Company, is expected to be only 2.5%. Additionally, out-migration has caused the province's population to decline by approximately 11.5% since 1992, negatively impacting the Company's customer and energy sales growth.

REGULATION

- The PUB regulates the Company under a cost-of-service methodology. Newfoundland Power has a favourable approved equity component of 45%.
- An automatic adjustment formula, applied annually between test years in November, is used to determine customer rates, effective January 1st of the following year, by adjusting the return on rate base to reflect changes in long-term Canada bond yields. The Company's ROE is based on a ten-day average of the three most recent series of long-term Canada bonds, and added to a risk premium. The approved return-on-rate base is adjusted when the calculated rate-of-return falls outside the approved range (+/- 18 basis points).
- The application of the automatic adjustment formula in November 2006 resulted in a reduction of the Company's ROE for the purpose of setting rates from 9.24% to 8.60% effective January 1, 2007.
- Furthermore, the Company also has a rate stabilization account, which passes through charges related to municipal taxes and fluctuations in the cost and quantity of fuel oil burned by NLH to produce power. Newfoundland Power's rates are adjusted annually on July 1 to reflect changes in the account.
- The Company also has a weather normalization reserve account, to adjust for the financial effect of variations in weather and stream flow when measured against long-term averages. This account helps to minimize the volatility of income from year to year.
- In December 2005, the Company received approval from the PUB to change its accounting policy for revenue recognition to the accrual method effective January 1, 2006. In its Order, the PUB also:
  - Approved the recognition in 2006 of approximately $3.1 million of a one-time accounting accrual arising as a result of the accounting policy change. Recognition of this amount offset increased income taxes in 2006 arising from the 2005 tax settlement with the Canada Revenue Agency (CRA).
  - Ordered the deferred recovery of approximately $5.8 million related to increased depreciation expense in 2006.
- In December 2006, the PUB approved the Company's 2007 Amortization and Cost Deferral Application, which requested: (1) the recognition of $2.7 million of unbilled revenue to offset the 2007 income tax effects of the 2005 tax settlement with the CRA; (2) the deferred recovery of capital asset amortization of $5.8 million caused by the conclusion of an amortization true-up in 2005; and (3) the deferred recovery of $1.1 million related to the cost of Rattling Brook replacement energy.

Demand Energy Rate

- The PUB required the establishment of a DER structure on January 1, 2005, for the power NLH sells to Newfoundland Power to encourage energy management for that company's customers.
  - The Company is billed on a demand component, based on its highest actual demand requirements from the previous winter season. The highest actual demand will be adjusted to reflect normal weather conditions, which reduces the forecast risk to the Company.
  - In the event that actual billing demand results in annual purchased power costs that differ by an amount greater than the threshold amount of +/-$521,000 for 2007, subject to final PUB approval (+/-$714,000 for 2006), the difference will be charged/rebated to customers, in a manner

to be determined by the PUB. The reserve mechanism was put in place for a three-year phase-in period beginning in 2005.

- The Company intends on filing a GRA with the PUB in 2007, for the purpose of setting customer rates for 2008. As part of its 2008 GRA the Company will need to address the increased marginal cost of purchased power as a result of NLH's 2007 GRA. Rates approved as a result of NLH's 2007 GRA are structured such that for each additional unit of electricity sold in excess of forecast the additional cost will be higher than the additional revenue. Consequently, as growth in electricity sales increases so may the frequency of the Company's applications for rate relief. DBRS notes that any additional cost will be fully recovered in 2007 through a rate stabilization account clause created to address this specific issue.

EARNINGS AND OUTLOOK

	For the 12-month period ended				
($ millions)	Dec. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec. 2002
Revenues	421.3	417.9	404.5	384.2	369.6
EBITDA	110.1	108.1	108.7	104.4	108.1
EBIT	77.0	76.0	77.7	75.1	72.6
Gross interest expense	34.1	32.6	31.4	31.3	27.9
Core net income	30.7	29.9	31.8	30.1	29.4
Net income (reported)	30.1	30.7	31.1	29.5	28.8
Return on average common equity	9.3%	9.3%	10.3%	10.4%	10.9%

Summary

- For the year ended December 31, 2006, EBIT increased slightly as a result of accounting accruals and deferrals:
  - The increase in revenues was primarily due to the recognition of $3.1 million in 2005 unbilled revenue, as approved by the PUB, to offset the effects of changing to the accrual basis of revenue recognition.
- EBITDA has been very stable as a result of increased revenues and balanced operating costs over the period.
- Interest expense has increased gradually since 2001 due to additional indebtedness the Company has been incurring to finance its capital expenditures.
- Net income has also remained flat as a result of lower income taxes. During the year, the Company's effective tax rate decreased to 30.8% from 32.9% in 2005.

Outlook

- The Company's regulated transmission and distribution operations are expected to continue generating stable earnings and cash flow in the future.
  - A strong housing market in recent years has contributed to a favourable level of sales growth, however, sales declined slightly in 2006 from 2005. Approximately 90% of new home construction installed electric heat in 2006.
- Due to application of the automatic adjustment formula, effective January 1, 2007, the Company's allowed ROE was reduced from 9.24% to 8.6%, causing forecast revenues to decline by approximately $2.5 million. DBRS estimates that this will negatively impact after-tax earnings by approximately $1.6 million.
- The DER may have an impact on pre-tax earnings, although DBRS notes that the maximum amount it could impact earnings is limited to +/-$521,000 for 2007, subject to final PUB approval (+/-$714,000 for 2006).

FINANCIAL PROFILE

($ millions)	For the 12-month period ended				
Cash Flow Statement	Dec. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec. 2002
Core net income	30.7	29.9	31.8	30.1	29.4
Depreciation and amortization	33.9	34.3	31.6	28.9	35.7
Other non-cash adjustments	(10.6)	(7.6)	(5.3)	(6.3)	(1.0)
Cash Flow From Operations	54.0	56.6	58.1	52.7	64.1
Dividends	(18.8)	(23.7)	(14.8)	(10.1)	(10.1)
Capital expenditures (1)	(57.1)	(53.7)	(58.9)	(63.0)	(58.8)
Free Cash Flow Before W/C Changes	(21.8)	(20.8)	(15.6)	(20.4)	(4.9)
Net changes in working capital	3.1	9.8	2.7	(3.3)	4.5
Net Free Cash Flow	(18.8)	(10.9)	(12.9)	(23.6)	(0.4)
Other investing activities	(0.3)	(0.4)	0.2	(0.1)	(9.3)
Other & adjustments	0.0	1.4	0.0	0.0	0.0
Amount to be Financed	(19.0)	(9.9)	(12.7)	(23.7)	(9.7)
Net debt financing	19.5	8.7	14.6	20.3	12.3
Net preferred financing	(0.1)	(0.0)	(0.0)	(0.3)	0.0
Net common equity	0.0	0.0	0.0	0.0	0.0
Net Change in Cash	0.4	(1.2)	1.8	(3.7)	2.6
% adjusted debt in capital structure	55.0%	54.7%	54.7%	55.1%	55.3%
Fixed-charges coverage (times)	2.20	2.27	2.40	2.33	2.51
Cash flow/adjusted debt	12.9%	14.2%	14.9%	14.0%	18.1%
Adjusted debt-to-EBITDA (times)	3.80	3.69	3.58	3.60	3.28

(1) Net of contributions from customers and security deposits.

Summary

Cash flow from operations over the past years, while benefiting from a stable level of earnings and deferrals, has exhibited modest variability, particularly in 2006 as a result of the $5.8 million deferred recovery of capital asset amortization.

- Capital expenditures have been relatively stable since 2002 as a result of a capital investment program which began that year.
  - On average 60% of capital expenditures are focused on the refurbishment of existing capital assets, 25% for extension of the electricity network to meet increasing customer service requirements and 15% for information system upgrades and general improvements.
- 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. As well, the Company manages the level of its dividends, in order to maintain a long-term capital structure of 55% debt and 45% equity, as deemed by the regulator.
  - Debt-to-capitalization remained relatively unchanged during this period.
  - Key credit ratios have trended downwards in recent years due to lower allowed ROEs and increased debt levels, needed to fund the ongoing capital expenditure program.
- Newfoundland Power's financial profile is considered to be favourable, with reasonable leverage in line with the deemed capital structure, and key credit ratios in line with the current rating.

Outlook

- The reduction in allowable ROE for 2007 may have a limited impact on cash flow from operations, but over the medium term the continued growth of the Company's rate base, although minimal, should help to offset this.
- Newfoundland Power's 2007 capital budget was approved by the PUB in September 2006 and contains 26 projects totalling $62.2 million. The focus will be on the replacement of aging equipment to strengthen the electricity system and meet the demand of customer and sales growth. The Rattling Brook Hydro Plant Refurbishment project,

which is budgeted at $18.8 million, constitutes 30% of the overall capital budget.

- The Company plans to invest approximately $276 million in plants and equipment from 2007 to 2011. On an annual basis, capital expenditures are expected to average approximately $55.2 million, slightly below the average over the past five years, positively impacting cash flow deficits which are expected to continue over the medium term. DBRS expects the company to continue funding cash flow shortfalls with borrowings under its credit facilities, long-term debt issuances, and through the management of dividends.
- Interest coverage and cash flow ratios are expected by DBRS to decline modestly in 2007, as they had in 2006, due to the approved use of accruals and amortization to achieve a fair and reasonable return. Credit ratios should remain relatively stable or improve over the medium term, depending upon the outcome of the Company's 2008 GRA, and continue to be consistent with the current rating.

LONG-TERM DEBT MATURITIES AND BANK LINES

($ millions)	2007	2008	2009	2010	2011	Thereafter	Total
Debt maturities	31.87	0.00	34.43	0.00	0.00	328.94	395.24
Sinking fund payments	3.85	3.85	3.85	3.85	3.85	0.00	19.25
as at Dec. 31, 2006	35.72	3.85	38.28	3.85	3.85	328.94	414.49

Summary

- Debt maturities are well spread out over the longer term, with maturity dates extending to 2035.
- Newfoundland Power's long-term debt consists of first mortgage bonds, which 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 and borrowings under revolving credit facilities.
- Newfoundland Power has the following credit facilities available to it:
  - A three-year, $100 million syndicated, committed revolving unsecured credit facility expiring in January 2009.
  - A $20 million uncommitted demand facility.
  - The credit facility contains a covenant which 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%.
- As of December 31, 2006, $34.7 million was outstanding on the Company's credit facilities.
- The Company is also restricted under its Trust Deed to meet specific tests when it intends on issuing additional long-term bonds. The Company must meet an Earnings Test where the net earnings 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 Company's credit facilities should be more than adequate to fund future working capital needs and free cash flow deficits.
- $34.4 million of the outstanding credit facilities has been classified as long-term borrowings, which the Company intends to refinance with long-term financing during future periods.

DESCRIPTION OF OPERATIONS

- Newfoundland Power is a vertically integrated utility serving approximately 229,000 customers throughout the island portion of the province of Newfoundland and Labrador. Its rate base as of December 31, 2006, was approximately $753 million.
- 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 136 MW.
- Approximately 90% of power requirements are purchased 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.

	For the 12-month period ended				
Electricity Sales - Breakdown (GWh)	Dec. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec. 2002
Residential	2,981	2,987	2,972	2,909	2,843
General service	2,014	2,017	2,007	1,973	1,922
Total sales	4,995	5,004	4,979	4,882	4,765
Growth in volume throughputs	-0.2%	0.5%	2.0%	2.5%	2.1%
Customers					
Residential	198,568	196,412	193,912	191,314	188,925
Commercial	30,932	30,889	30,552	30,339	30,147
Total	229,500	227,301	224,464	221,653	219,072

	For the 12-month period ended				
Energy Generated (GWh)	Dec. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec. 2002
Energy generated	417	426	424	425	424
Energy purchased	4,876	4,873	4,841	4,725	4,604
Energy generated + purchased	5,293	5,299	5,265	5,150	5,028
Less: transmission losses + internal use	298	295	286	268	263
Total sales	4,995	5,004	4,979	4,882	4,765
System losses and internal use	6.0%	5.9%	5.7%	5.5%	5.5%
Installed Generation Capacity (MW)					
Hydroelectric	92.1	94.6	94.6	94.6	94.5
Gas turbine	36.5	43.9	43.9	43.9	46.9
Diesel	7	7	7	5.9	6.9
Total	135.6	145.5	145.5	144.4	148.3
Peak demand (MW)	1,166	1,124	1,167	1,118	1,194

Newfoundland Power Inc.

Balance Sheet	As at				As at		
($ millions)	Dec. 2006	Dec. 2005	Dec. 2004	**Liabilities & Equity**	Dec. 2006	Dec. 2005	Dec. 2004
Assets				Short-term debt	0.7	0.8	58.1
Cash + equivalents	0.0	0.0	0.5	Debt due one yr.	35.7	4.3	3.7
Accounts receivable	61.6	58.7	59.6	A/P + accr'ds	65.2	56.8	56.1
Inventories	4.9	5.2	5.4	Other	11.4	12.7	10.9
Prepaids & other	12.0	10.5	10.1	**Current Liabilities**	113.1	74.5	128.8
Current Assets	78.5	74.4	75.5	Long-term debt	378.8	391.0	324.9
Net fixed assets	669.54	651.46	630.08	Deferred & other	51.7	51.1	45.8
Regulatory assets	45.5	34.0	28.7	Preferred equity	9.4	9.4	9.4
Deferred charges & other	95.2	90.1	91.0	Shareholders' equity	335.9	324.0	316.4
Total	888.8	850.1	825.3	**Total**	888.8	850.1	825.3

Ratio Analysis	For the 12-month period ended				
	Dec. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec. 2002
Current ratio	0.69	1.00	0.59	0.44	0.60
Accumulated depreciation/gross fixed assets	40.2%	40.0%	40.0%	40.4%	40.1%
Cash flow/adjusted debt (1)	12.9%	14.2%	14.9%	14.0%	18.1%
Cash flow/capital expenditures	94.6%	105.5%	98.7%	83.7%	108.9%
Cash flow-dividends/capital expenditures	61.7%	61.3%	73.5%	67.7%	91.7%
% debt in capital structure	54.6%	54.3%	54.3%	54.7%	54.9%
% adjusted debt in capital structure (1)	55.0%	54.7%	54.7%	55.1%	55.3%
Maximum deemed common equity	45%	45%	45%	45%	45%
Common dividend payout ratio	60.4%	78.8%	45.7%	32.2%	33.0%
Coverage Ratios					
EBIT interest coverage	2.26	2.33	2.47	2.40	2.60
EBITDA interest coverage	3.23	3.32	3.46	3.34	3.87
Fixed-charges coverage	2.20	2.27	2.40	2.33	2.51
Adjusted debt/EBITDA (1)	3.80	3.69	3.58	3.60	3.28
Earnings Quality/Operating Efficiency					
Power purchases/revenues	61.0%	61.3%	61.7%	60.6%	58.1%
EBIT margin	18.3%	18.2%	19.7%	20.0%	20.0%
Net margin (before extras)	7.3%	7.2%	8.0%	8.0%	8.1%
Return on avg. common equity (before extras)	9.3%	9.3%	10.3%	10.4%	10.9%
Allowed ROE – mid-point	9.24%	9.24%	9.75%	9.75%	9.05%
Customers/employee (2)	415.8	408.8	374.7	365.8	359.1
Growth of customer base (2)	1.0%	1.3%	1.3%	1.2%	1.0%
GWh sold/employee (2)	9.0	9.0	8.3	8.1	7.9
Rate base ($ millions)	750	745	714	676	573
Growth in rate base	0.6%	4.4%	5.6%	18.0%	5.1%

(1) Preferred shares are considered to be 70% equity, 30% debt. (2) Company restated employee figures.

Note:
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

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Key Indicators

Newfoundland Power Inc.

	2006	2005	2004	2003
(CFO Pre-W/C + Interest) / Interest Expense [1]	**2.7x**	**2.9x**	**3.0x**	**2.9x**
(CFO Pre-W/C) / Debt	**14.1%**	**15.7%**	**16.0%**	**15.6%**
(CFO Pre-W/C - Dividends) / Debt	**9.8%**	**10.1%**	**12.5%**	**13.1%**
(CFO Pre-W/C - Dividends) / Capex	**69.0%**	**74.4%**	**81.8%**	**77.4%**
Debt / Book Capitalization [2]	**55.8%**	**63.2%**	**55.5%**	**56.0%**
EBITA Margin %	**17.7%**	**19.6%**	**19.6%**	**19.5%**

[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] 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

Company Profile

Newfoundland Power Inc (NPI) is a vertically integrated electric utility which operates under cost of service regulation as administered by the Board of Commissioners of Public Utilities of Newfoundland and Labrador (PUB) under the Public Utilities Act (the Act). It is a wholly-owned subsidiary of Fortis Inc. (not rated), an electric utility holding company.

NPI owns and maintains over 10,000 kilometers of transmission and distribution lines and delivers electricity to approximately 229,000 commercial and residential customers on the island portion of the Province of Newfoundland and Labrador. Generation forms a relatively small portion of NPI's revenues and assets consequently NPI purchases approximately 90% of its power requirements from the provincially-owned Newfoundland & Labrador Hydro (Hydro). NPI generates the balance of its power requirements via 23 hydro plants, three diesel plants and three gas turbine facilities, which in aggregate have an installed capacity of roughly 135.6MW. NPI's power purchases from Hydro are regulated by the PUB, and costs of purchased power are passed through to ratepayers.

Recent Developments

Since Moody's initial rating of NPI in 2005, NPI's cash flow credit metrics have weakened somewhat. For instance (CFO Pre-W/C)/Debt has declined from 16.0% in 2004 to 14.1% in 2006. Similarly, CFO Pre-W/C Interest Coverage has declined from 3.0x in 2004 to 2.7x in 2006. Moody's believes that this deterioration reflects the fact that NPI has not had a rate increase since 2003 when rates were increased following the company's 2002 general rate application (GRA). It also reflects the impact of declining bond yields which have resulted in lower allowed returns on rate base and ROE by operation of the annual automatic adjustment formula utilized by the PUB to adjust rates between GRAs. As a result of the foregoing, NPI has experienced declining FFO while debt levels and interest expense have increased resulting in the weakening of the company's cash flow credit metrics. The company expects to file a GRA in 2007, with any changes to rates to take effect in 2008.

Rating Rationale

Pursuant to Moody's Global Regulated Electric Utilities Rating Methodology, NPI is considered to be a low risk utility given that its operations are wholly regulated and that it operates in Canada, a jurisdiction that is generally viewed as having one of the more supportive regulatory environments for utilities on a global basis. NPI's ratios are generally consistent with, albeit somewhat weaker than, those of other Baa1 companies that are predominantly engaged in transmission and distribution such as Atlantic City Electric and FortisAlberta (a sister company to NPI). Atlantic City Electric and FortisAlberta have reported (CFO Pre-W/C)/Debt in the 16-19% range versus NPI's sub-15% level. Similarly, Atlantic City Electric and FortisAlberta have reported CFO Pre-W/C Interest Coverage in the 3.5-4.5x range versus NPI's sub 3x range.

The Baa1 rating assigned to the First Mortgage Bonds (FMB) is reflective of the FMB's 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 pre-approved by the PUB.

The rating also reflects NPI's low business risk as a cost of service-regulated monopoly utility whose operations are predominantly transmission and distribution which Moody's generally believes to be the lowest risk segments for electric utilities. The fact that NPI's service territory is geographically isolated, and therefore largely removed from competition, and exhibits relatively low, predictable growth contributes to Moody's view of NPI as a low risk utilitiy. Moody's considers NPI's regulatory environment to be relatively supportive and notes that the rate making construct includes measures that largely eliminate NPI's exposure to commodity price and volume risk. Furthermore, Moody's expects that the Newfoundland electricity market is unlikely to undergo significant restructuring in the foreseeable future.

The rating considers NPI's status as a subsidiary of its parent, Fortis Inc., a Canadian utility holding company. While NPI is one of a number of utility operating companies owned by Fortis, Moody's considers NPI to be operationally and financially independent from Fortis. While the parent could seek to increase dividend payments from NPI to support the operations of the holding company or other utility operating companies, the level of dividends has not historically been stressful for NPI. This is consistent with Fortis' philosophy of allowing its utility subsidiaries to operate on a stand-alone basis. Moody's expects that NPI will continue to implement a dividend policy which will maintain its capital structure at or near the 45% maximum equity permitted by the PUB. Furthermore, NPI's financial independence is supported by features of its credit agreements and of the Act. NPI's bank credit agreement contains covenants which prohibit affiliate loans and guarantees and place meaningful restrictions on all other affiliate transactions. The Act prohibits the provision of inter-corporate loans which would disadvantage the interest of ratepayers or which would provide little benefit to ratepayers or NPI.

Moody's views NPI's liquidity facilities to be supportive of its rating. In January 2006, NPI replaced its $100 million, 364-day syndicated committed revolving credit facility with a $100 million, three-year syndicated committed revolving facility. The facility can be extended at the Lenders' discretion. While the facility does not have the term-out provision that its previous 364-day facility contained, Moody's expects that NPI will seek to extend the facility prior to its second anniversary in order to ensure that the company never has less than one year's committed liquidity available to it. Moody's notes that availability under NPI's syndicated credit facility could be constrained in adverse circumstances due to the existence of a Material Adverse Change (MAC) clause. However, the MAC clause is tempered by a carve-out for adverse weather conditions, which is one of the most likely events that could negatively affect the company's performance. The credit facility will be utilized in part to fund NPI's capital expenditure program of approximately $55-$65 million in the coming years. As of December 31, 2006, approximately $34.4 million was drawn against the committed credit facility.

NPI expects to periodically issue additional FMBs to refund borrowings under the syndicated credit facility. NPI has a manageable maturity profile, with the next significant maturity of approximately $35.7 million occurring later in 2007 but no other maturities (with the exception of annual 1% sinking fund installments) until 2014. Moody's expect that NPI will refinance the $35.7 million FMB maturity in 2007 with the issuance of additional FMBs. Consistent with most electric utilities, it is expected that NPI will continue to be modestly free cash flow negative after capital spending and dividends for the foreseeable future, assuming moderate but steady cash flow, relatively constant capital expenditures, and no large changes to dividend policy.

Rating Outlook

The rating outlook is stable based on the expectation that NPI's 2007 GRA will result in a strengthening of the company's cash flow credit metrics beginning in 2008. If it appears that in 2008 NPI's (CFO Pre-W/C)/Debt will be materially below 15% or that its CFO Pre-W/C Interest Coverage will be materially less than 3.0x, the company's outlook and rating could be negatively impacted.

What Could Change the Rating - Up

The rating could be positively impacted if NPI could demonstrate expectations for a sustained improvement in financial ratios, such as CFO Pre-W/C Interest Coverage above 4.0x and (CFO Pre-W/C)/Debt above 20%. This level of improvement in NPI's credit metrics could result from a rate increase, coupled with either an increase in equity in the capital structure or the equity risk premium utilized by the regulator to automatically adjust the allowed rate of return on rate base between full cost of capital hearings. Moody's considers an upward revision in NPI's rating to be unlikely in the near term.

What Could Change the Rating - Down

NPI's rating could be negatively impacted if by 2008 CFO Pre-W/C Interest Coverage has not met or exceeded 3.0x and (CFO Pre-W/C)/Debt has not met or exceeded 15%.

Rating Factors

Newfoundland Power Inc.

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[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

Newfoundland Power Inc.

Credit Metrics - OPEBS on Cash Basis

Pre-tax Interest Coverage (times)

Allowed Common Equity	**Allowed Return On Equity**											
	10.75%	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**	**8.25%**	**8.00%**
45%	2.81	2.77	2.73	2.68	2.64	2.60	2.56	2.52	2.48	2.44	2.40	2.35
44%	2.75	2.71	2.67	2.63	2.59	2.55	2.51	2.47	2.43	2.39	2.35	2.31
43%	2.70	2.66	2.62	2.58	2.54	2.50	2.46	2.42	2.39	2.35	2.31	2.27
42%	2.64	2.60	2.57	2.53	2.49	2.45	2.42	2.38	2.34	2.30	2.27	2.23
41%	2.59	2.55	2.52	2.48	2.44	2.41	2.37	2.33	2.30	2.26	2.23	2.19
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**											
	10.75%	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**	**8.25%**	**8.00%**
45%	3.21	3.19	3.16	3.13	3.10	3.08	3.05	3.02	2.99	2.97	2.94	2.91
44%	3.17	3.14	3.11	3.09	3.06	3.03	3.01	2.98	2.95	2.93	2.90	2.87
43%	3.12	3.09	3.07	3.04	3.02	2.99	2.97	2.94	2.91	2.89	2.86	2.84
42%	3.07	3.05	3.02	3.00	2.97	2.95	2.92	2.90	2.87	2.85	2.83	2.80
41%	3.03	3.00	2.98	2.96	2.93	2.91	2.88	2.86	2.84	2.81	2.79	2.76
40%	2.98	2.96	2.94	2.91	2.89	2.87	2.84	2.82	2.80	2.78	2.75	2.73

Cash Flow to Debt (percentage)

Allowed Common Equity	**Allowed Return On Equity**											
	10.75%	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**	**8.25%**	**8.00%**
45%	16.55	16.34	16.14	15.94	15.74	15.54	15.34	15.14	14.94	14.73	14.53	14.33
44%	15.78	15.59	15.40	15.21	15.02	14.83	14.64	14.45	14.26	14.07	13.88	13.69
43%	15.07	14.89	14.71	14.53	14.35	14.17	13.99	13.81	13.63	13.45	13.28	13.10
42%	14.40	14.23	14.06	13.89	13.73	13.55	13.38	13.22	13.05	12.88	12.71	12.54
41%	13.78	13.62	13.46	13.30	13.14	12.98	12.82	12.66	12.49	12.33	12.17	12.01
40%	13.19	13.04	12.89	12.74	12.58	12.43	12.28	12.13	11.98	11.83	11.67	11.52

Newfoundland Power Inc.

Credit Metrics - OPEBS on Accrual Basis

Pre-tax Interest Coverage (times)

Allowed Common	Allowed Return On Equity											
Equity	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**	**8.25%**	**8.00%**
45%	2.84	2.80	2.76	2.71	2.67	2.63	2.59	2.55	2.51	2.47	2.43	2.38
44%	2.78	2.74	2.70	2.66	2.62	2.58	2.54	2.50	2.46	2.42	2.38	2.34
43%	2.73	2.69	2.65	2.61	2.57	2.53	2.49	2.45	2.42	2.38	2.34	2.30
42%	2.67	2.63	2.60	2.56	2.52	2.48	2.45	2.41	2.37	2.33	2.30	2.26
41%	2.62	2.58	2.54	2.51	2.47	2.43	2.40	2.36	2.33	2.29	2.25	2.22
40%	2.56	2.53	2.49	2.46	2.42	2.39	2.35	2.32	2.28	2.25	2.21	2.18

Cash Flow Interest Coverage (times)

Allowed Common	Allowed Return On Equity											
Equity	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**	**8.25%**	**8.00%**
45%	3.36	3.33	3.30	3.27	3.25	3.22	3.19	3.16	3.14	3.11	3.08	3.06
44%	3.31	3.28	3.25	3.23	3.20	3.17	3.15	3.12	3.10	3.07	3.04	3.02
43%	3.26	3.23	3.21	3.18	3.16	3.13	3.11	3.08	3.05	3.03	3.00	2.98
42%	3.21	3.19	3.16	3.14	3.11	3.09	3.06	3.04	3.01	2.99	2.96	2.94
41%	3.17	3.14	3.12	3.09	3.07	3.05	3.02	3.00	2.97	2.95	2.93	2.90
40%	3.12	3.10	3.07	3.05	3.03	3.00	2.98	2.96	2.94	2.91	2.89	2.87

Cash Flow to Debt (percentage)

Allowed Common	Allowed Return On Equity											
Equity	**10.75%**	**10.50%**	**10.25%**	**10.00%**	**9.75%**	**9.50%**	**9.25%**	**9.00%**	**8.75%**	**8.50%**	**8.25%**	**8.00%**
45%	17.66	17.46	17.26	17.06	16.86	16.66	16.45	16.25	16.05	15.85	15.65	15.45
44%	16.86	16.67	16.48	16.29	16.10	15.91	15.72	15.53	15.34	15.15	14.96	14.77
43%	16.11	15.93	15.75	15.57	15.39	15.21	15.03	14.85	14.67	14.49	14.31	14.13
42%	15.41	15.24	15.07	14.90	14.73	14.56	14.39	14.22	14.05	13.88	13.71	13.54
41%	14.75	14.59	14.43	14.27	14.11	13.95	13.79	13.63	13.47	13.30	13.14	12.98
40%	14.13	13.98	13.83	13.68	13.52	13.37	13.22	13.07	12.92	12.77	12.61	12.46

Newfoundland Power Inc.

2008 Forecast Average Rate Base[1]
Impact of Asset Rate Base Method
($000s)

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

[1] All amounts shown are averages.
[2] The reduction in plant investment is due to the change in the capitalized portion of OPEBs. *See Section 3.6, Employee Future Benefits.*
[3] Reclassification of unamortized deferred debt issue costs from rate base to WACC. *See Section 3.4.1, Asset Rate Base Method.*
[4] *See Section 3.4.1, Asset Rate Base Method.*

Newfoundland Power Inc.

2008 Revenue Requirements[1]
($000s)

		Existing	Changes	Proposed
1	**Return on Rate Base**	54,204	17,166	71,370
2				
3	**Other Costs**			
4	Purchased Power Costs	328,786	(1,077)	327,709
5	Operating Costs	48,723	(833)	47,890
6	Pension and Early Retirement Costs	3,348	-	3,348
7	OPEB Costs	-	6,370	6,370
8	Amortization of Cost Recovery Deferral - Depreciation	-	2,317	2,317
9	Depreciation	41,002	(795)	40,207
10	Income Taxes	14,256	8,101	22,357
11		436,115	14,083	450,198
12				
13	**Total Costs and Return**	490,319	31,249	521,568
14				
15	**Adjustments**			
16	Other Revenue	(10,801)	(1,210)	(12,011)
17	Non-regulated Expenses	(983)	-	(983)
18	Other Adjustments[3]	-	92	92
19				
20	**2008 Revenue Requirement**	**478,535**	**30,131**	**508,666**
21				
22	Revenue Deferral Amortizations	-	(6,180)	(6,180)
23				
24	**Revenue Required From Rates**	**478,535**	**23,951** [2]	**502,486**

[1] *See Section 3.9, 2008 Revenue Requirements* for a summary of the Company's 2008 Revenue Requirements proposals.

[2] Excludes price elasticity impacts related to revenue of $2.6 million. The required revenue increase in 2008 of $26.6 million is comprised of $24.0 million from line 25 and price elasticity impacts of $2.6 million (See Exhibit 11, line 1, Column D).

[3] Includes $62,000 related to the amortization of capital stock issue expenses and $30,000 related to customer security deposits.

Newfoundland Power Inc.

2008 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Invested Capital**			
3	Total Debt	450,632	(11,790) [1]	438,842
4	Preference Shares	9,353	-	9,353
5	Common Equity	356,043	8,250 [2]	364,293
6		816,028	(3,540)	812,488
7				
8	**Average Invested Capital Ratios**			
9	Total Debt	55.22%	-1.21% [1]	54.01%
10	Preference Shares	1.15%	-	1.15%
11	Common Equity	43.63%	1.21% [2]	44.84%
12		100.00%	0.00%	100.00%
13				
14	**Cost of Capital**			
15	Debt	7.33%	0.36% [1]	7.69%
16	Preference Shares	6.27%	-	6.27%
17	Common Equity	5.85%	4.40% [2]	10.25%
18				
19	**Weighted Average Cost of Capital**			
20	Debt	4.05%	0.10%	4.15%
21	Preference Shares	0.07%	-	0.07%
22	Common Equity	2.55%	2.05%	4.60%
23		6.67%	2.15%	8.82%
24				
25	**Returns**			
26	Return on Debt	33,034	409 [1]	33,443
27	Return on Preference Shares	586	-	586
28	Regulated Return on Common Equity	20,843	16,498 [2]	37,341
29	Z Factor Effects	(259)	259 [3]	-
30	**Return on Rate Base**	54,204	17,166	71,370

[1] Reflects reduced borrowing requirements resulting from the proposed increase in cash revenue.
[2] Reflects the Company's proposed return on common equity of 10.25 percent in 2008.
[3] Return on rate base under the ARBM does not require the inclusion of a Z Factor. *See Section 3.3.3, Automatic Adjustment Formula.*

Newfoundland Power Inc.

2008 Average Rate Increase
($000s)

	Existing[1]	Proposed[2]	Difference	Price Elasticity[3]	Proposed Increase[4]
	A	B	C	D	E
Revenue From Rates	478,535	502,486	23,951	2,606	26,557
RSA Charges	22,741	22,593	(148)	148	-
MTA Charges	11,935	12,499	564	67	631
Total	513,211	537,578	24,367	2,821	27,188
Customer Rate Change[5]					**5.3%**

[1] Revenue from existing rates from Exhibit 9. RSA based on the RSA factor (0.444¢/kWh) effective January 1, 2007. MTA based on MTA Factor (1.02393) effective July 1, 2006.

[2] Revenue from proposed rates from Exhibit 9. RSA based on the RSA factor (0.444 ¢/kWh) effective January 1, 2007. MTA based on MTA factor (1.02393) effective July 1, 2006.

[3] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the 5.3 percent rate increase. Determined by applying existing rates to the 2008 test year sales forecast adjusted for the elasticity impacts and comparing results to Column A.

[4] Difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C plus Column D).

[5] Total of Column E expressed as percentage of (Column A less Column D).

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NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

The Company shall include a rate stabilization adjustment in its rates. This adjustment shall reflect the accumulated balance in the Company's Rate Stabilization Account ("RSA") and any change in the rates charged to the Company by Newfoundland and Labrador Hydro ("Hydro") as a result of the operation of its Rate Stabilization Plan ("RSP").

I. RATE STABILIZATION ADJUSTMENT ("A")

The Rate Stabilization Adjustment ("A") shall be calculated as the total of the Recovery Adjustment Factor and the Fuel Rider Adjustment.

The Recovery Adjustment Factor shall be recalculated annually, effective the first day of July in each year, to amortize over the following twelve (12) month period the annual plan recovery amount designated to be billed by Hydro to the Company, and the balance in the Company's RSA.

The Recovery Adjustment Factor expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{B + C}{D}$$

Where:

B = the annual plan recovery amount designated to be billed by Hydro during the next twelve (12) months commencing July 1 as a result of the operation of Hydro's RSP.

C = the balance in the Company's RSA as of March 31st of the current year.

D = the total kilowatt-hours sold by the Company for the 12 months ending March 31st of the current year.

The Fuel Rider Adjustment shall be recalculated annually, effective the first day of July in each year, to reflect changes in the RSP fuel rider applicable to Newfoundland Power. The Fuel Rider Adjustment expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{E}{D} \times F$$

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NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

I. RATE STABILIZATION ADJUSTMENT ("A") (Cont'd)

Where:

D = corresponds to the D above.

E = the total kilowatt-hours of energy (including secondary energy) sold to the Company by Hydro during the 12 months ending March 31 of the current year.

F = the fuel rider designated to be charged to Newfoundland Power through Hydro's RSP.

The Rate Stabilization Adjustment ("A") shall be recalculated and be applied as of the effective date of a new wholesale mill rate by Hydro, by resetting the Fuel Rider Adjustment included in the Rate Stabilization Adjustment to zero.

II. RATE STABILIZATION ACCOUNT ("RSA")

The Company shall maintain a RSA which shall be increased or reduced by the following amounts expressed in dollars:

1. At the end of each month the RSA shall be:

(i) increased (reduced) by the amount actually charged (credited) to the Company by Hydro during the month as the result of the operation of its Rate Stabilization Plan.

(ii) increased (reduced) by the excess cost of fuel used by the Company during the month calculated as follows:

$$\mathbf{(G/H - P) \quad x \quad H}$$

Where:

G = the cost in dollars of fuel and additives used during the month in the Company's thermal plants to generate electricity other than that generated at the request of Hydro.

H = the net kilowatt-hours generated in the month in the Company's thermal plants other than electricity generated at the request of Hydro.

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NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

P = the **2nd block** base rate in dollars per kilowatt-hour paid during the month by the Company to Hydro for firm energy.

(iii) reduced by the price differential of firmed-up secondary energy calculated as follows:

$$\mathbf{(P - J) \times K}$$

Where:

J = the price in dollars per kilowatt-hour paid by the Company to Hydro during the month for secondary energy supplied by Deer Lake Power and delivered as firm energy to the Company.

K = the kilowatt-hours of such secondary energy supplied to the Company during the month.

P = corresponds to P above.

(iv) reduced (increased) by the amount billed by the Company during the month as the result of the operation of the Rate Stabilization Clause calculated as follows:

$$\mathbf{\frac{L \times A}{100}}$$

Where:

L = the total kilowatt-hours sold by the Company during the month.

A = the Rate Stabilization Adjustment in effect during the month expressed in cents per kilowatt-hour.

(v) increased (reduced) by an interest charge (credit) on the balance in the RSA at the beginning of the month, at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base.

2. On the 31st of December in each year, ~~**commencing in 1989,**~~ the RSA shall be increased (reduced) by the amount that the Company billed customers under the Municipal Tax Clause for the ~~**previous**~~ calendar year is less (or greater) than the amount of municipal taxes **paid** for that year**.**

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NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

3. The annual kilowatt-hours used in calculating the Rate Stabilization Adjustment to the monthly streetlighting rates are as follows:

	Fixture Size (watts)				
	100	150	175	250	400
Mercury Vapour	-	-	840	1,189	1,869
High Pressure Sodium	546	802	-	1,273	1,995

4. On December 31st, 2007, the RSA shall be reduced (increased) by the amount that the increase in the Company's revenue for the year resulting from the change in base rates attributable to the flow through of Hydro's wholesale rate change, effective January 1, 2007, is greater (or less) than the amount of the increase in the Company's purchased power expense for the year resulting from the change in the base rate charged by Hydro effective January 1, 2007.

   The methodology to calculate the RSA adjustment at December 31, 2007 is as follows:

Calculation of increase in Revenue:	
2007 Revenue with Flow-through (Q)	$ -
2007 Revenue without Flow-through (R)	$ -
Increase in Revenue (S = Q – R)	$ -
Calculation of increase in Purchased Power Expense:	
2007 Purchased Power Expense with Hydro Increase (T)	$ -
2007 Purchased Power Expense without Hydro Increase (U)	$ -
Increase in Purchased Power Expense (V = T – U)	$ -
Adjustment to Rate Stabilization Account (W = S – V)	$ -

   Where:

   Q = Normalized revenue from base rates effective January 1, 2007.
   R = Normalized revenue from base rates determined based on rates pursuant to the operation of the Automatic Adjustment Formula for 2007.
   T = Normalized purchased power expense from Hydro's wholesale rate effective January 1, 2007 (not including RSP rate).
   U = Normalized purchased power expense determined based on Hydro's wholesale rate effective January 1, 2006 (not including RSP rate).

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NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

5. **On December 31st of each year, the Rate Stabilization Account (RSA) shall be increased (reduced) by the Energy Supply Cost Variance.**

   This Energy Supply Cost Variance identifies the change in purchased power cost that is related to the difference between purchasing energy at the 2nd block energy charge in the wholesale rate and the test year energy supply cost reflected in customer rates.

   The Energy Supply Cost Variance expressed in dollars shall be calculated as follows:

$$\frac{(A - B) \times (C - D)}{100}$$

   Where:

   A = the wholesale rate 2nd block charge per kWh.

   B = the test year energy supply cost per kWh determined by applying the wholesale energy rate to the test year energy purchases and expressed in ¢ per kWh.

   C = the weather normalized annual purchases in kWh.

   D = the test year annual purchases in kWh.

III. RATE CHANGES

The energy charges in each rate classification (other than the energy charge in the "Maximum Monthly Charge" in classifications having a demand charge) shall be adjusted as required to reflect the changes in the Rate Stabilization Adjustment. The new energy charges shall be determined by subtracting the previous Rate Stabilization Adjustment from the previous energy charges and adding the new Rate Stabilization Adjustment. The new energy charges shall apply to all bills based on consumption on and after the effective date of the adjustment.

Newfoundland Power Inc.

Regulation Changes

Existing Regulation 9(b)

Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay the Company in advance a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material.

Proposed Regulation 9(b)

Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay the Company a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material. The payment may be required in advance or, subject to credit approval, billed to the Customer.

Existing Regulation 9(c)

Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay the Company in advance the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment.

Proposed Regulation 9(c)

Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay the Company the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment. The payment may be required in advance or, subject to credit approval, billed to the Customer.

Newfoundland Power Inc.

Cost Breakdown of Rejected Payment

Bank Fee:	$	3.50
Cash Control Clerk Labour: (backout of payment from file, rebalance files, queue entry to Call Centre staff) Average of 10 minutes per item = $22.82/hr*34% loading = $30.58/hr*10/60 =	$	5.10
Customer Account Representative Labour: (Contact to customer, document notes on act., Send written correspondence if unable to contact by phone.) Average of 15 minutes per item = $24.27/hr*34% loading = $32.52*15/60 =	$	8.13
Total Cost:	**$**	**16.73**

Newfoundland Power Inc.

Survey of Rejected Payment Charges

Company	Coverage / Comments	Amount
BC Hydro	Regulations state "Returned Cheque" Same charge as well for pre-authorized payment.	$ 20.00
FortisBC	Returned Cheque Service Charge. Covers NSF (non-sufficient funds) cheque charge.	$ 20.00
Epcor	Returned Cheque Charge Covers cheques and pre-authorized payments.	$ 20.00
ENMAX	Referred to as "Dishonoured Cheques for any reason".	$ 25.00
ATCO Electric	Returned Cheque Fee.	$ 20.00
SaskPower	NSF Cheque Charge.	$ 25.00
Fortis Ontario[1]	Returned Cheque Fee (includes pre-authorized payments).	See footnote
Manitoba Hydro	NSF Payments (includes pre-authorized payments).	$ 20.00
Yukon Electric	Returned Cheque Charge.	$ 20.00
Hydro Ottawa	Returned Payment Charge.	$ 15.00 + bank charges
Toronto Hydro	Returned Cheque Fee. Includes pre-authorized payments.	$ 15.00
Veridian Connections	Any returned bank item.	$ 15.00
Hydro Quebec	"Cheque with insufficient funds."	$ 10.00
New Brunswick Power	"Non-Sufficient Funds Charge".	$ 15.00
Maritime Electric	"Non-Sufficient Funds Charge".	$ 16.50
Nova Scotia Power	Returned Cheque or Rejected pre-authorized payment.	$ 18.00

[1] Eastern Ontario Power and Canadian Niagara Power Inc. both charge $15.00 plus bank charges. Cornwall Electric charges $15.00.

Newfoundland Power Inc.

Regulation Change for Rejected Payment

Existing Regulation 10(d)

Where a Customer's cheque is not honoured for insufficient funds, a charge of $10.00 may be applied to the Customer's bill.

Proposed Regulation 10(d)

Where a Customer's cheque or automated payment is not honoured by their financial institution, a charge of $16.00 may be applied to the Customer's bill.