NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

September 14, 2012

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: 2013/2014 General Rate Application

1. Background

By Order No. P.U. 43 (2009), the Board, in effect, ordered Newfoundland Power to file its next general rate application no later than May 31, 2012 with a 2013 test year. In Order No. P.U. 25 (2011), the Board ordered, in effect, that the process and timing with respect to the Company's next general rate application would be established by a further direction of the Board. On May 29, 2012, the Board directed Newfoundland Power to file its next general rate application, with a 2013 test year, by September 14, 2012.

The filing enclosed with this letter complies with the Board's direction.

2. The Filing

Enclosed with this letter are the original and 13 copies of a general rate application for a review of Newfoundland Power's 2013 and 2014 costs and customer rates (the "Application").

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

Volume 1: ***Application and Company Evidence:*** *this Volume contains this letter; the formal Application; and the Company Evidence.*

Volume 2: ***Exhibits and Supporting Materials:*** *this Volume contains the Exhibits to the Company Evidence and supporting forecasts, reports, and studies prepared by the Company.*

Volume 3: ***Expert Evidence and Studies:*** *this Volume contains the expert cost of capital evidence of Ms. Kathleen McShane and Dr. James Vander Weide and the Depreciation Study based upon plant in service at December 31, 2010 prepared by Gannett Fleming.*

The Application proposes that the Board approve an overall average increase in Newfoundland Power's current customer rates of approximately 6.0%, with effect from March 1, 2013.

The average increase in rates is primarily the result of two changes in Newfoundland Power's cost of service. Firstly, the effect of rebalancing 2013-2014 supply costs with revenue from rates accounts for approximately 2.6% of the proposed increase. Secondly, increasing Newfoundland Power's ratemaking return on equity for 2013 and 2014 accounts for approximately 1.8% of the increase. The remaining approximately 1.6% results from a mixture of other cost changes.

In the Application, Newfoundland Power is proposing specific changes to its cost of capital, regulatory accounting, regulatory deferrals and customer rates.

3. Application Proposals

A summary of the Application proposals follows.

Cost of Capital

A central issue in this Application is Newfoundland Power's cost of capital for 2013 and 2014. The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2013 and 2014 is 10.4% to 10.5%. Further, the automatic adjustment formula used annually to establish the Company's cost of equity (the "Formula") does not, in the Company's view, accurately estimate a fair return on equity under current financial market conditions.

The Application specifically proposes:

1. a ratemaking return on equity for the Company of 10.4% for 2013 and 2014; and

2. that the Formula be discontinued on account of current financial market conditions.

Regulatory Accounting

In the Application, Newfoundland Power is proposing certain regulatory accounting changes.

The Application specifically proposes, commencing in 2013, that the Company:

1. implement new depreciation rates and amortize an accumulated reserve variance of $2.6 million based on the 2010 Depreciation Study filed with the Application;

2. recognize pension expense for regulatory purposes in accordance with U.S. GAAP;

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3. defer annual customer energy conservation program costs and recovered them over a seven year period; and

4. credit, or recover, year-end balances in the Weather Normalization Reserve annually through the RSA.

Regulatory Amortizations
In the Application, Newfoundland Power is proposing a number of amortizations through 2015.

The Application specifically proposes three-year amortizations commencing in 2013 for:

1. certain cost recovery deferrals approved in 2011 and 2012;

2. Consumer Advocate and Board hearing costs associated with the Application;

3. the year-end 2011 balance in the Weather Normalization Reserve; and

4. a 2013 revenue shortfall resulting from a forecast March 1, 2013 implementation of the proposed customer rate changes.

Customer Rates
The Application proposes a number of changes to customer rates. The customer rates proposed in the Application were derived to provide the proposed 2013 and 2014 revenue requirements. The rate proposals also reflect the Company's most recent cost of service study and recommendations of the Retail Rate Review undertaken by Newfoundland Power in consultation with the Consumer Advocate, Newfoundland and Labrador Hydro, and Board staff.

The rates, tolls and charges proposed in the Application will result in average increases in proposed customer rates by class as follows:

Rate Class	***Average Increase***
Domestic	7.2%
General Service 0-100 kW (110 kVA)	0.6%
General Service 110-1000 kVA	6.0%
General Service 1000 kVA and Over	6.0%
Street and Area Lighting	6.0%

The proposed rates also change structural aspects of current rates. Existing Rates 2.1 (0 to 10 kW) and 2.2 (0 to 100 kW (110 kVA)) are to be merged into a single General Service Rate for all

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customers with demands of less than 100 kW. Demand and energy charges are to be modified to better reflect marginal costs. There are also changes to energy block sizes in Rates 2.3 and 2.4; changes to basic customer charges in all rate classes; and changes to a number of other charges and rates.

Concluding

The Application has been forwarded directly to Newfoundland and Labrador Hydro and Mr. Thomas Johnson, the Consumer Advocate.

It is Newfoundland Power'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.

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

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

Yours very truly,

Peter Alteen
Vice President,
Regulation & Planning

Enclosures

c. Geoffrey Young (3 copies)
Newfoundland and Labrador Hydro

Thomas Johnson (4 copies)
Messrs. O'Dea Earle
Consumer Advocate

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VOLUME 1: APPLICATION & COMPANY EVIDENCE

A. APPLICATION

B. COMPANY EVIDENCE

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VOLUME 2: EXHIBITS & SUPPORTING MATERIALS

A. EXHIBITS

B. REPORTS

1. Five-Year Energy Conservation Plan: 2012 - 2016
2. Labour Forecast 2012-2014
3. 2013 and 2014 Rate Base Allowances
4. Customer, Energy and Demand Forecast
5. Cost of Service Study
6. Customer Rate Impacts
7. Supply Cost Mechanisms

VOLUME 3: EXPERT EVIDENCE & STUDIES

1. Cost of Capital: Ms. Kathleen McShane
2. Cost of Capital: Dr. James Vander Weide
3. Depreciation Study: Gannett Fleming Inc.

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 2013 and 2014.

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

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

A. Introductory:

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, in effect, that a public utility 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 No. P.U. 43 (2009), the Board, in effect, ordered Newfoundland Power to file its next general rate application no later than May 31, 2012 with a 2013 test year. In Order No. P.U. 25 (2011), the Board, in effect, ordered that the process and timing with respect to the Company's next general rate application would be established by a further direction of the Board. On May 29, 2012, the Board directed Newfoundland Power to file its next general rate application, with a 2013 test year, by September 14, 2012.

4. The Application complies with the Orders and direction of the Board as described in paragraph 3 hereof.

B. Background:

5. By Order Nos. P.U. 16 (1998-99), P.U. 36 (1998-99), P.U. 19 (2003), P.U. 32 (2007) and P.U. 43 (2009), the Board, in effect, ordered that an automatic adjustment formula be established and maintained to annually set Newfoundland Power's rate of return and customer electricity rates to reflect changes in long term Government of Canada bond yields (the "Formula").

6. 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.

7. By Order No. P.U. 32 (2007), the Board ordered that Newfoundland Power establish a Demand Management Incentive ("DMI") Account and by Order No. P.U. 43 (2009), the Board, in effect, ordered that Newfoundland Power file a report on the performance of the DMI Account with the Application.

8. By Order Nos. P.U. 27 (2011) and P.U. 11 (2012), the Board, in effect, approved Newfoundland Power's 2012 adoption of U.S. GAAP for regulatory purposes.

9. Newfoundland Power last filed a depreciation study with the Board based upon plant in service as at December 21, 2005.

C. Newfoundland Power Proposals:

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

11. Newfoundland Power proposes that the Board approve the calculation of depreciation expense with effect from January 1, 2013 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 the remaining life of the assets an accumulated reserve variance of approximately $2.6 million identified in the Depreciation Study filed with the Application;

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

12. Newfoundland Power proposes that the Board approve, with effect from January 1, 2013:

    (a) the calculation of defined benefit pension expense for regulatory purposes in accordance with U.S. GAAP; and

    (b) the amortization over 15 years of the forecast defined benefit pension expense regulatory asset of approximately $12.4 million;

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

13. Newfoundland Power proposes that the Board approve, with effect from January 1, 2013, the deferral and amortization of annual customer energy conservation program costs over

a seven year period as more fully set out in the evidence filed in support of the Application.

14. Newfoundland Power proposes that the Board approve, with effect from January 1, 2013, the annual disposition of prior year end balances in the Weather Normalization Reserve through the Rate Stabilization Account as more fully set out in the evidence filed in support of the Application.

15. Newfoundland Power proposes that the Board approve amortizations, for the period 2013 through 2015, to:

(a) amortize the recovery over a three year period of certain cost recovery deferrals approved in 2011 and 2012;

(b) amortize the recovery over a three year period of an estimated $1.25 million in Board and Consumer Advocate costs related to the Application;

(c) amortize over a three year period the outstanding year end balance for 2011 in the Weather Normalization Reserve of approximately $5.0 million due to customers; and

(d) amortize the recovery over a three year period of a forecast 2013 revenue shortfall of an estimated $980,000;

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

16. Newfoundland Power proposes that the Board approve an overall average increase in current customer rates of 6.0%, with effect from March 1, 2013, based upon:

(a) a forecast average rate base for 2013 of $917,891,000 and for 2014 of $954,123,000;

(b) a rate of return on average rate base for 2013 of 8.64% in a range of 8.46% to 8.82%, and for 2014 of 8.58% in a range of 8.40% to 8.76%; and

(c) forecast revenue requirements from customer rates for 2013 of $601,551,000 and for 2014 of $618,846,000;

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

17. Newfoundland Power proposes that the Board approve rates, tolls and charges effective for service provided on and after March 1, 2013, as set out in Schedule A to the Application which result in average increases in proposed customer rates by class as follows:

Rate Class	***Average Increase***
Domestic	7.2%
General Service 0-100 kW (110 kVA)	0.6%
General Service 110-1000 kVA	6.0%
General Service 1000 kVA and Over	6.0%
Street and Area Lighting	6.0%

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

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

(a) reflect changing fuel costs between test years for customers that benefit from the maximum monthly charges provided for in proposed Rate 2.1 and existing Rates 2.3 and 2.4;

(b) reflect the most recent energy consumption information for street and area lighting fixtures;

(c) permit recovery through the Rate Stabilization Account of customer energy conservation program costs; and

(d) permit credit, or recovery, through the Rate Stabilization Account of annual transfers to the Weather Normalization Reserve;

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

D. Order Requested:

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

(a) pursuant to Section 80 of the Act, the discontinuation of use of the Formula as set out in paragraph 10 of the Application;

(b) pursuant to Section 68 of the Act, the calculation of depreciation expense as set out in paragraph 11 of the Application;

(c) pursuant to Sections 58 and 80 of the Act, the calculation of defined benefit pension expense for regulatory purposes in accordance with U.S. GAAP and the amortization of the regulatory asset as set out in paragraph 12 of the Application;

(d) pursuant to Sections 58 and 80 of the Act, the amortization of annual customer energy conservation program costs, including a definition of the Conservation and Demand Management Cost Deferral Account as set out in paragraph 13 of the Application;

(e) pursuant to Sections 58 and 80 of the Act, the annual disposition of year end balances in the Weather Normalization Reserve through the Rate Stabilization Account as set out in paragraph 14 of the Application;

(f) pursuant to Sections 58 and 80 of the Act, the amortizations set out in paragraph 15 of the Application;

(g) pursuant to Sections 70 and 80 of the Act, rates, tolls and charges as set out in Schedule A which reflect paragraphs 16 and 17 of the Application subject to modification for any intervening Order of the Board affecting rates, tolls and charges;

(h) pursuant to Sections 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 18 of the Application; and

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

E. Communications:

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

DATED at St. John's, Newfoundland, this 14th day of September, 2012.

NEWFOUNDLAND POWER INC.

Ian F. Kelly, Q.C. and Gerard M. Hayes
Newfoundland Power Inc.
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St. John's, NL A1B 3P6

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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 2013 and 2014.

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, Regulation and Planning, 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 14th day of September, 2012,
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)

Basic Customer Charge:
Not Exceeding 200 Amp Service ....$15.68 per month
Exceeding 200 Amp Service ....$20.68 per month

Energy Charge:
All kilowatt-hours ....@12.055¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service ....$15.68 per month
Exceeding 200 Amp Service ....$20.68 per month

Discount:

A discount of 1.5% of the amount of the current month's bill 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 #1.1S
DOMESTIC SEASONAL - OPTIONAL

Availability:

Available upon request for Service to Customers served under Rate #1.1 Domestic Service who have a minimum of 12 months of uninterrupted billing history at their current Serviced Premises.

Rate:

The Energy Charges provided for in Rate #1.1 Domestic Service Rate shall apply, subject to the following adjustments:

Winter Season Premium Adjustment (Billing months of December through April):
All kilowatt-hours ....@ 0.953¢ per kWh

Non-Winter Season Credit Adjustment (Billing Months of May through November):
All kilowatt-hours ....@ (1.297)¢ per kWh

Special Conditions:

1. An application for Service under this rate option shall constitute a binding contract between the Customer and the Company with an initial term of 12 months commencing the day after the first meter reading date following the request by the Customer, and renewing automatically on the anniversary date thereof for successive 12-month terms.

2. To terminate participation on this rate option on the renewal date, the Customer must notify the Company either in advance of the renewal date or no later than 60 days after the anniversary/renewal date. When acceptable notice of termination is provided to the Company, the Customer's billing may require adjustment to reverse any seasonal adjustments applied to charges for consumption after the automatic renewal date.

NEWFOUNDLAND POWER INC.
RATE #2.1
GENERAL SERVICE 0-100 kW (110 kVA)

Availability:

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

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ....$22.25 per month

Demand Charge:
$8.69 per kW of billing demand in the months of December, January, February and March and $6.19 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month in excess of 10 kW.

Energy Charge:
Energy Charge:
First 3,500 kilowatt-hours ....@ 11.999 ¢ per kWh
All excess kilowatt-hours ....@ 9.442 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 17.931 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

Single Phase ....$22.25 per month
Three Phase ....$35.98 per month

Discount:

A discount of 1.5% of the amount of the current month's bill 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)

Basic Customer Charge: ....$50.00 per month

Demand Charge:
$7.53 per kVA of billing demand in the months of December, January, February and March and $5.03 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 50,000 kilowatt-hours ....@ 10.740 ¢ per kWh
All excess kilowatt-hours ....@ 8.965¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 17.931 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill 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)

Basic Customer Charge: ....$85.00 per month

Demand Charge:
$7.14 per kVA of billing demand in the months of December, January, February and March and $4.64 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 75,000 kilowatt-hours ....@ 10.202 ¢ per kWh
All excess kilowatt-hours ....@ 8.712 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 17.931 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill 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)

	Sentinel/Standard	Post Top
High Pressure Sodium*		
100W (8,600 lumens)	$17.37	$18.78
150W (14,400 lumens)	22.13	-
250W (23,200 lumens)	31.67	-
400W (45,000 lumens)	43.98	-

* For all new installations and replacements.

Mercury Vapour		
175W (7,000 lumens)	$17.37	$18.78
250W (9,400 lumens)	22.13	-
400W (17,200 lumens)	31.67	-

Special poles used exclusively for lighting service**	
Wood	$ 7.31
30' Concrete or Metal, direct buried	10.57
45' Concrete or Metal, direct buried	14.89
25' Concrete or Metal, Post Top, direct buried	8.07
Underground Wiring (per run)**	
All sizes and types of fixtures	$12.93

** 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.

NEWFOUNDLAND POWER INC.
TIME OF DAY RATE STUDY
DOMESTIC SERVICE

Availability:

Available to Customers served under Rate #1.1 Domestic Service who participate in the Time of Day Rate Study.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge:
Not Exceeding 200 Amp Service ....$15.68 per month
Exceeding 200 Amp Service ....$20.68 per month

Energy Charges:

Winter On-Peak kWh ....17.368¢ per kWh
Winter Off-Peak kWh ....11.902¢ per kWh
Non-Winter kWh..10.701¢ per kWh

Minimum Monthly Charge .... $15.68 per month

Winter On-Peak:

The Winter On-Peak period is defined as the hours starting at 8:00 a.m. to 12:00 p.m. and 4:00 p.m. to 8:00 p.m. Monday through Friday for the billing months of December through March (Winter Months).

Winter Off-Peak:

The Winter Off-Peak period is defined as all hours not included above in the On-Peak period including all weekends for the Winter Months.

Non-Winter:

The Non-Winter period is defined as the billing months of April through November.

Discount:

A discount of 1.5% of the amount of the current month's bill 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.
TIME OF DAY RATE STUDY
GENERAL SERVICE 1000 kVA AND OVER

Availability:

Available to Customers served under Rate #2.4 General Service 1000 kVA and Over who participate in the Time of Day Rate Study.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge.. $85.00 per month

Demand Charge:

$1.97 per kVA of billing demand. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charges:

Winter On-Peak kWh ....15.010¢ per kWh
Winter Off-Peak kWh ....9.861¢ per kWh
Non-Winter kWh...8.895¢ per kWh

Minimum Monthly Charge .... $85.00 per month

Winter On-Peak:

The Winter On-Peak period is defined as the hours starting at 8:00 a.m. to 12:00 p.m. and 4:00 p.m. to 8:00 p.m. Monday through Friday for the billing months of December through March (Winter Months).

Winter Off-Peak:

The Winter Off-Peak period is defined as all hours not included above in the On-Peak period including all weekends for the Winter Months.

Non-Winter:

The Non-Winter period is defined as the billing months of April through November.

Discount:

A discount of 1.5% of the amount of the current month's bill 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.**

SECTION 1: INTRODUCTION

1.1 APPLICATION BACKGROUND

1.1.1 Newfoundland Power

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.

Newfoundland Power is dependent upon Newfoundland and Labrador Hydro ("Hydro") for approximately 93% of the electricity which the Company delivers to its customers.

Table 1-1 shows the number of customers served by Newfoundland Power and the annual weather adjusted sales for the period 2010 to 2014F.

Table 1-1
Customers and Sales
2010 to 2014F

	2010	**2011**	**2012F**	**2013F**	**2014F**
Customers	243,426	247,163	250,737	254,059	257,267
Sales (GWhs)	5,419	5,553	5,681	5,751	5,823

From 2010 to 2014F, the number of customers served by the Company is expected to increase by an average of 1.4% per year. Annual weather adjusted sales are expected to increase by an average of 1.8% per year over this period. Newfoundland Power's outlook for growth in the number of customers and sales reflects both short term factors and longer term economic and demographic trends.

1.1.2 Outlook

Newfoundland Power's outlook reflects a balance of the operational realities associated with the least cost delivery of electrical service to customers and the financial realities associated with earning a fair return on the capital invested in the business.

Success in the continued least cost delivery of safe, reliable electrical service to customers is dependent upon a variety of factors. Among these are operational efficiency, customer responsiveness, and workforce effectiveness.

Newfoundland Power's operations are efficient. Operating costs are stable and reflective of sustainable labour efficiency.

Newfoundland Power continues to be reasonably responsive to customer expectations. Customers increasingly choose to deal with the Company via a variety of electronic means. This adds a degree of complexity and cost to the Company's customer operations.

Continued operational efficiency and customer responsiveness are dependent upon the skills and diligence of the Company's employees and upon Newfoundland Power's application of technology. The essentials of electricity distribution engineering have been established for decades. The systems needed to effectively operate and manage engineered assets, however, are evolving technologically. Newfoundland Power's customer service interface is also increasingly dependent on technology. These developments are not new. But they do take on greater significance in the period of workforce transition into which the Company has entered. More technologically capable customers have specific, and somewhat different, service expectations. More technologically enabled employees will be required to meet those expectations on a least cost basis.

Newfoundland Power employee retirements have increased and are expected to remain high for the next few years. The level of hiring required in this period is expected to exceed that experienced by the Company for at least two decades. Increased recruitment, training and development efforts will also affect the Company's costs and overall operating efficiency.

Newfoundland Power's electricity system performance continues to be reliable. This is primarily a reflection of stable capital investment in the business.

Newfoundland Power's day to day operations are well managed. But this does not mean that the Company is not exposed to business risk on a day to day basis.

Some aspects of this risk are described in this Application. For example, the Company's service territory has historically experienced some of the most hazardous conditions for electricity system operations. Blizzards and severe ice conditions reflect one seasonal dimension of this. Increased frequency of tropical storms and hurricanes may be another dimension. Incidents of these severe weather conditions have tested the Company's responsiveness a number of times since the last general rate application.

Workforce demographics present another example of these aspects of the Company's business risk. Newfoundland Power is currently managing its workforce demographic transition reasonably; however, this does not mean that the workforce transition currently under way does not present a measure of risk in relation to the Company's future capabilities both to fulfill its obligation to serve its customers and to earn its return.

There are also longer term risks. The population of Newfoundland and Labrador is forecast to continue to decline and it is aging at the fastest rate in Canada. These customer demographic trends have implications for investment and long term cost recovery. The future of electricity supply similarly has potential implications for future cost recovery for Newfoundland Power.

These considerations are important to the investors who fund the capital investment that is critical to the least cost delivery of safe, reliable electrical service to Newfoundland Power's customers. Given the long life of utility assets, amounts invested in the electricity system in 2013 or 2014 will not be recovered for decades. Investors who provide that capital expect, and are entitled to, fair compensation for this investment on a continuing basis.

The automatic adjustment formula which establishes the Company's annual forecast cost of equity (the "Formula") was continued by the Board after Newfoundland Power's last general rate application. Last November, the Formula indicated the cost of equity for Newfoundland Power for 2012 was 7.85%. Currently, the Formula is indicating the cost of equity for Newfoundland Power for 2013 is 7.53%. These returns do not represent fair compensation for the Company's equity capital. For this reason, in this Application, Newfoundland Power is proposing that the Formula be discontinued.

Financial market conditions have been extraordinary for the past few years. Determination of a fair return in these conditions is challenging. It is a central issue in this Application.

1.2 APPLICATION PROPOSALS

1.2.1 2013 and 2014 Revenue Requirements

In this Application, Newfoundland Power is requesting an average increase in current customer rates of approximately 6.0% effective March 1, 2013. This increase is primarily the result of two changes in the Company's cost of service.

The first relates to Newfoundland Power's energy supply costs. A general rate application requires forecast electricity supply costs to be reconciled with forecast revenue from rates for the test period. The effect of rebalancing 2013 and 2014 supply costs with revenue from rates accounts for an approximate 2.6% increase from current customer rates. Between test periods, increases in supply costs related to increases in customer electricity usage are recovered through the energy supply cost variance mechanism originally approved by the Board after the Company's 2008 general rate application.

The second relates to Newfoundland Power's future return on equity. In this Application, the Company has filed expert evidence indicating that a fair return on equity for Newfoundland Power in 2013 and 2014 is 10.4% to 10.5%. This is higher than the ratemaking return on equity approved by the Board for 2012 of 8.8%. Increasing Newfoundland Power's ratemaking return on equity for 2013 and 2014 accounts for an approximate 1.8% increase from current customer rates.

The remaining 1.6% increase from current customer rates results from a mixture of cost changes. These include the rebalancing of 2013 and 2014 employee future benefits costs to customer rates (changes in these costs are currently recovered on an annual basis through the Rate Stabilization Adjustment (the "RSA")) and increased depreciation costs resulting from the Company's continuing investment in the electricity system. This 1.6% increase also includes the effects of cost related proposals contained in this Application relating to conservation cost recovery and accounting for weather normalization impacts, both of which reduce 2013 and 2014 revenue requirements. Newfoundland Power's overall operating costs associated with the delivery of service to customers continue to grow, but at a rate that is less than inflation.

1.2.2 Customer Rates

While this Application proposes an *average* increase in customer rates of 6.0%, the proposed rate increases are not uniform. This Application proposes a number of changes to customer rates and rate structures as a result of the Retail Rate Review, which was commenced by agreement following the Company's 2008 general rate application.

Newfoundland Power is proposing to merge its existing Rates 2.1 and 2.2 which apply to small general service customers with loads of 100 kW or less. The new merged Rate 2.1 will be fairer to customers. Revenue from each of these rates is materially higher than the Company's cost to serve these customers.

On average, customers served under the merged Rate 2.1 will receive rate increases of approximately 0.6%. Primarily as a result of the proposed changes to the Company's small general service customer rates, the proposed increase for the Company's residential customers is 7.2%. For the remainder of the Company's customer rates, the proposed increase is 6.0%. These proposals are aimed at ensuring greater fairness in recovery of Newfoundland Power's cost of service from all customer classes.

For Rates 2.3 and 2.4, which apply to larger general service customers, the Company is also proposing changes to the energy block sizes and basic customer charges. For Newfoundland Power's residential customers, the basic customer charge is proposed to remain unchanged for customers served at 200 amps or less. A separate basic customer charge is proposed for customers served at over 200 amps.

Finally, a number of changes to components of various rates are proposed, including changes in (i) the difference between winter and non-winter demand charges for general service customers; (ii) payment discounts for all residential and general service customers; and (iii) the treatment of the maximum monthly charge in future RSA adjustments.

1.2.3 Other Proposals

In 2008, Newfoundland Power and Hydro agreed to the first joint provincial energy conservation plan. Under this plan, Newfoundland Power expects to deliver gross customer energy savings of approximately 28 GWh per year by the end of 2012. These savings are enduring in nature and will avoid fuel costs at Hydro's Holyrood thermal generating station ("Holyrood") every year. Hydro and Newfoundland Power recently agreed to a second joint provincial energy conservation plan which is directed at increasing the level of customer energy savings. In this Application, Newfoundland Power is proposing to defer and amortize customer energy conservation program costs over a 7 year period commencing in 2013. This proposal is aimed at better matching the long term benefits of Newfoundland Power's customer energy conservation programming with the costs of that programming.

In this Application, Newfoundland Power is also seeking approval of (i) revised depreciation rates which reflect the results of its most recent study; (ii) the recognition of pension expense in accordance with U.S. GAAP; and (iii) the credit to, or recovery from, customers of annual Weather Normalization Reserve balances through the RSA. All of these approvals are proposed to be effective in 2013.

SECTION 2: CUSTOMER OPERATIONS

2.1 OVERVIEW

Newfoundland Power's customer operations are primarily focused upon stable electricity system reliability; reasonable response to evolving customer service preferences; and maintenance of sustainable levels of operating efficiency. This has resulted in reasonable continuing levels of customer satisfaction with the service the Company delivers.

To be responsive to customers' desire to lower their electricity bills, Newfoundland Power introduced a broader customer energy conservation portfolio in 2009. Commencing in 2013, the Company plans to expand this portfolio. This will increase the Company's costs but result in lower customer electricity bills and additional avoided Holyrood production costs of approximately $9.4 million annually by year end 2014.

Newfoundland Power's workforce management is consistent with continuity in the provision of safe, reliable service to customers. Increased recruitment and training requirements add costs; however, overall labour costs are consistent with least cost service delivery over both the short and long term.

Newfoundland Power's forecast 2013 and 2014 operating and capital costs are appropriate for the purpose of establishing customer rates. These costs are required for the management and operation of the electricity system at the lowest possible cost consistent with the provision of safe, reliable service to Newfoundland Power's customers.

2.2 SERVING CUSTOMERS

2.2.1 Customer Operations

Customer satisfaction with the service provided by Newfoundland Power has been reasonably stable since 2007. This reflects the Company's responsiveness to customer expectations for reliable, electrical service delivery at the lowest reasonable cost.

Overall, Newfoundland Power's customers experience stable electricity system reliability. This is the result of the Company's continuing capital and operating maintenance programs. However, severe weather conditions have, at times, presented challenges to reliable electricity system operations.

Newfoundland Power responds reasonably to evolving service preferences of its customers, including the expectation of more diverse electronic means of dealing with the Company.

Newfoundland Power's operating costs indicate reasonable and sustainable efficiency in customer operations.

Customer Satisfaction

Newfoundland Power conducts customer surveys on a quarterly basis.[1] The Company uses these survey results as a broad indicator of overall customer satisfaction with their electrical service. These surveys have indicated that the service attributes most important to customers are service reliability and price.

[1] Newfoundland Power's customer surveys have been performed quarterly by independent third parties since 1998.

Table 2-1 shows Newfoundland Power's customer satisfaction index from 2007 to 2011.

Table 2-1
Customer Satisfaction Index
2007 to 2011

2007	**2008**	**2009**	**2010**	**2011**
8.75	8.91	8.95	8.92	8.85

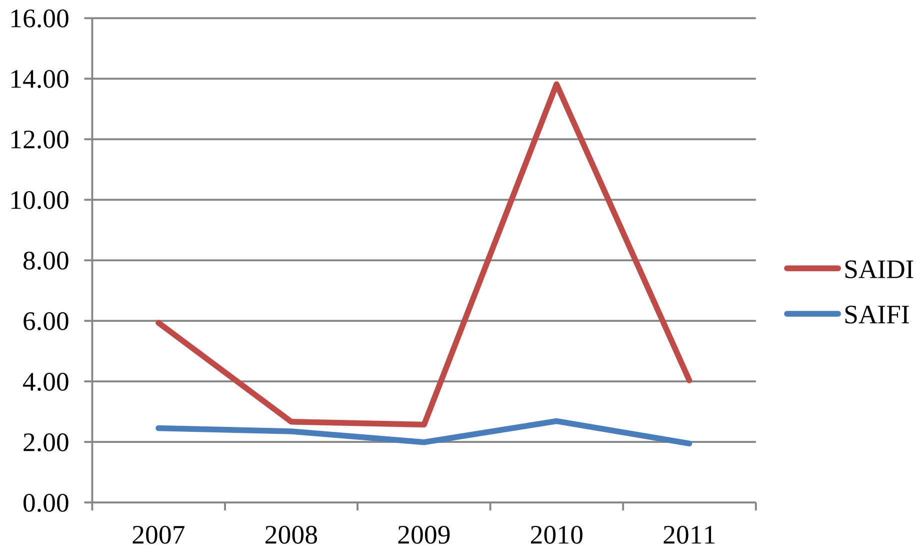
From 2007 to 2011, customers' satisfaction with the service provided by Newfoundland Power has been relatively stable.

Electricity System Performance

Electricity system reliability is a key indicator of the performance of an electricity distribution utility such as Newfoundland Power.

Graph 2-1 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for Newfoundland Power's electricity system from 2007 to 2011.[2]

Graph 2-1
SAIDI and SAIFI
2007 to 2011



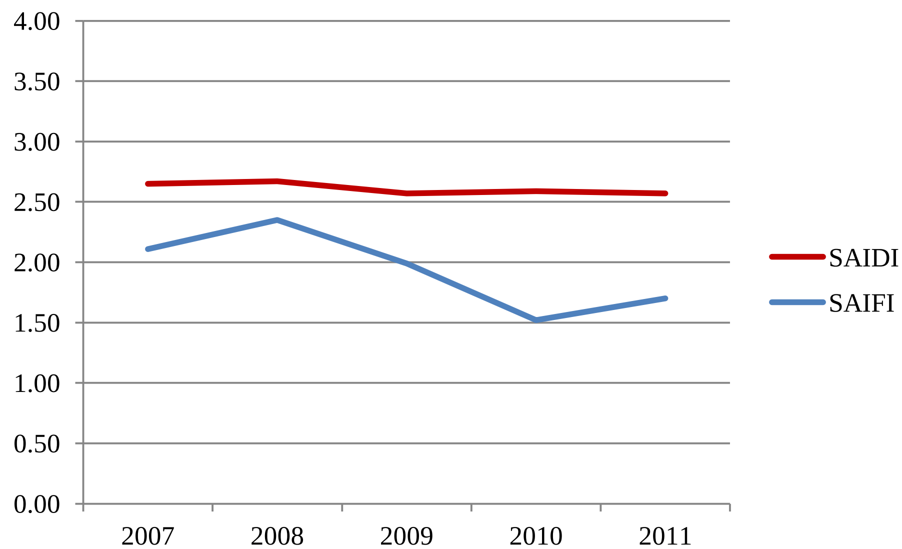
From 2007 to 2011, the *number* of outages experienced by Newfoundland Power's customers has been relatively stable and averaged approximately 2.3 per year. Through this period, the *hours* of outage experienced by the Company's customers has been more variable and ranged from an average of approximately 2.6 hours per customer in 2009 to an average of approximately

[2] SAIDI measures the average number of customer *hours* of electrical supply outage in a year. SAIFI measures the average *number* of customer outages in a year.

13.8 hours per customer in 2010. This variability is a direct result of severe weather conditions.[3] In addition, severe weather conditions have had material cost impacts for Newfoundland Power.[4]

Graph 2-2 shows SAIDI and SAIFI from 2007 to 2011 adjusted to remove the effects of severe weather events.[5]

Graph 2-2
SAIDI and SAIFI
Excluding Severe Weather Events
2007 to 2011



The adjusted SAIDI and SAIFI indicate stable electricity system reliability from 2007 to 2011.

This principally reflects the overall condition of Newfoundland Power's electrical system assets

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3 For 2007, SAIDI was approximately 5.9 hours per customer due primarily to a severe ice storm which affected the Burin, Bonavista and northern Avalon Peninsulas in December 2007. For 2010, SAIDI was approximately 13.8 hours per customer due primarily to a severe ice storm which affected the Bonavista Peninsula in March 2010 and Hurricane Igor which occurred in September 2010 and had a more widespread effect.

4 The impacts of Hurricane Igor, for example, were described in Newfoundland Power applications to the Board in November 2010 and April 2011 which were approved in Order Nos. P.U. 35 (2010) and P.U. 11 (2011). The cost impacts of severe weather events are a prominent feature of Newfoundland Power's business risk profile.

5 This data excludes the severe weather events described in Footnote 3.

and the Company's continuing capital and operating maintenance programs.[6]

Customer Service Response

Continued growth in the number of customers and the evolving service preferences of customers has resulted in an increase in the number of customer service interactions to which the Company must respond.[7]

Table 2-2 shows the number of Newfoundland Power customer initiated contacts received via telephone at the Customer Contact Center and via the Company's website from 2007 to 2011.[8]

Table 2-2
Customer Initiated Contacts
Telephone and Website
2007 to 2011
(000s)

	2007	**2008**	**2009**	**2010**	**2011**
Telephone	518	480	464	470	477
Website	393	471	450	464	542
Totals	**911**	**951**	**914**	**934**	**1,019**

From 2007 to 2011, the total number of customer initiated contacts with Newfoundland Power via telephone and the website have increased by approximately 12%. While the number of telephone contacts has declined by approximately 8%, visits to the website have increased by

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6 It is a generally accepted engineering observation that electricity system reliability is primarily influenced by the condition of the electricity system assets. A significant portion of Newfoundland Power's annual capital investment is focused on the replacement and refurbishment of deteriorated assets. In the 10 year period from 2007 to 2016, asset replacement is forecast to account for approximately 50% of Newfoundland Power's capital expenditure. The Company's annual electricity system operating maintenance expenditures are shown in Table 2-6 on page 2-10.

7 From 2007 to 2011, the total number of customers served by Newfoundland Power grew from 232,262 to 247,163, an increase of approximately 6.4%.

8 These are not the only customer initiated contacts received by Newfoundland Power. Other contacts occur routinely in person, by mail, through the Company's Outage Notification System, by email, and through the joint Newfoundland Power/Hydro *takeCHARGE!* website.

approximately 38%. In 2011, customer initiated contacts with Newfoundland Power through the Company's website exceeded customer initiated contacts by telephone for the first time.

Customers are also increasingly choosing to contact the Company by electronic mail, or email.

Table 2-3 shows the number of Newfoundland Power customer initiated contacts received via email from 2007 to 2011.

Table 2-3
Customer Initiated Contacts
Email
2007 to 2011

2007	2008	2009	2010	2011
23,685	32,848	33,503	41,125	46,643

From 2007 to 2011, the number of customer initiated contacts with Newfoundland Power via email has increased by approximately 97%.

Increasing numbers of customers are also choosing to receive their bills for service electronically.

Table 2-4 shows the number of Newfoundland Power customers participating in electronic billing or *eBills* from 2007 to 2011.

Table 2-4
***eBills* Participation**
2007 to 2011

2007	2008	2009	2010	2011
18,843	23,270	28,056	35,071	45,389

At year end 2011, approximately 18% of Newfoundland Power's customer accounts were billed via *eBills*. This compares to approximately 8% at year end 2007.[9]

While maintaining traditional means of customer communications, such as the telephone, the Company has been reasonably responsive to an increasing diversity of customer contact preferences, particularly electronic preferences. This impacts Newfoundland Power's operations in a number of ways. The provision of services through electronic means can cost less per transaction than similar services provided through traditional means. For example, electronic billing is a lower cost alternative for bill distribution than regular mail.[10] However, provision of additional customer service alternatives tends to increase operational complexity and costs.[11]

Efficiency in Operations

Meeting customers' expectations requires Newfoundland Power to achieve a reasonable balance between quality of service and cost.

Table 2-5 shows Newfoundland Power's gross operating cost per customer from 2010 to 2014F;[12] and gross operating cost per customer excluding customer energy conservation costs on

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9 This 10% increase in total participation in *eBills* is broadly consistent with the Company's experience with respect to electronic payments. From 2007 to 2011, electronic customer payments to the Company increased by 9% to approximately 79% of total customer payments.

10 Compared to paper based billing, electronic billing costs approximately $8.00 less per customer per year.

11 Adapting the Company's website to provide specific data to an increasing range of devices commonly used by customers (i.e., iPhone, Android and Blackberry) is a continuing aspect of this complexity. The costs of modifications to the Company's website were approximately $130,000 and $123,000 in 2010 and 2011, respectively, and are forecast to be approximately $183,000 in 2012.

12 Gross operating cost per customer is calculated by dividing operating costs (net of employee future benefit costs, deferrals and amortizations) as shown in *Exhibits 1 and 2* in *Volume 2, Exhibits & Supporting Materials*, by the number of customer accounts at year end. In 2011, the Company adopted the accrual method of accounting for Other Post Employment Benefits (see Order No. P.U. 31 (2010)). For consistency of presentation, cash OPEBs costs of approximately $793,000 are excluded from 2010 in Table 2-5 on page 2-9.

a nominal and inflation adjusted basis for the same period.[13]

Table 2-5
Gross Operating Cost per Customer
2010 to 2014F
($)

	2010	**2011**	**2012F**	**2013F**	**2014F**
Costs per Customer	220	231	228	233	241
Cost per Customer (excluding Conservation)	208	216	216	217	220
Inflation Adjusted (excluding Conservation) ($2010)[14]	208	207	201	196	192

From 2010 to 2014F, Newfoundland Power's gross operating cost per customer is forecast to increase. This is primarily a result of the introduction and expansion of the Company's customer energy conservation efforts.

When customer energy conservation costs are excluded, Newfoundland Power's gross operating cost per customer is forecast to increase by approximately $12, or 5.8%, from 2010 to 2014F. On an inflation adjusted basis, Newfoundland Power's gross operating cost per customer excluding customer energy conservation costs is forecast to decrease by approximately $16, or 7.7%, from 2010 to 2014F.

[13] The Company's customer energy conservation costs for 2010 to 2014 are detailed in *Section 2.2.2 Conservation Programming*. Assessment of Newfoundland Power's operating efficiency excluding these costs is reasonable for a number of reasons. Firstly, Newfoundland Power's customer energy conservation programs are justified on the basis of reduced electricity production costs of Hydro. The increased operating cost incurred by Newfoundland Power effectively results in a larger reduction in supply costs from Hydro. This benefits Newfoundland Power's customers but this benefit is not reflected in Newfoundland Power's operating costs. Secondly, the benefits of increased customer energy conservation programming tend to materialize over time whereas the costs associated with development and implementation of the programs tend to be front end loaded. This creates timing differences between the costs and the benefits which complicate assessment of operational efficiency. Thirdly, Newfoundland Power's customer energy conservation costs are expected to increase materially from approximately $2.9 million in 2010 to approximately $5.5 million in 2014. This can tend to mask underlying efficiency in the Company's core electrical distribution and customer service operations.

[14] Labour costs are adjusted for inflation using Newfoundland Power's composite labour rate increases of 4.95% in 2011; 3.71% in 2012; 4.09% in 2013; and 4.06% in 2014. Other, or non-labour costs are adjusted for inflation using the GDP deflator for Canada, a measure recognized by the Board as reasonable in Order No. P.U. 36 (1998-1999).

Newfoundland Power's operating costs reflect reasonable and sustainable levels of cost efficiency.

Effective use of technology contributes to this cost efficiency. For example, the Company uses electronic means to collect engineering and operations data in the field; organize asset maintenance standards and field data; and, schedule and dispatch maintenance work. This has enabled Newfoundland Power to improve efficiency in its maintenance operations.

Table 2-6 shows Newfoundland Power's annual electricity system maintenance costs from 2010 to 2014F.

Table 2-6
Electricity System Maintenance Costs
2010 to 2014F
($ Millions)

2010	2011	2012F	2013F	2014F
17.5	17.9	18.0	18.4	18.8

From 2010 to 2014F, operating costs for electricity system maintenance are forecast to be stable.

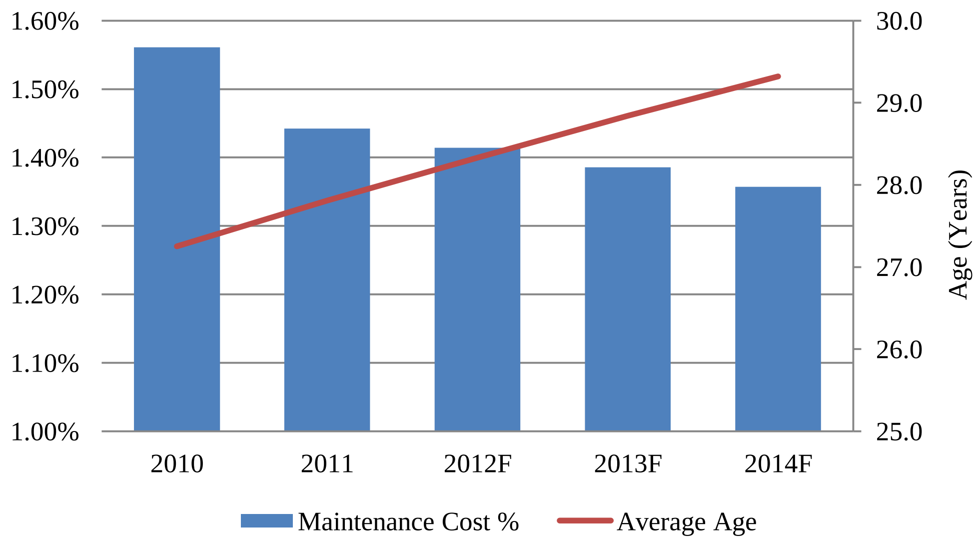
During the period 2010 to 2014F, the average age of Newfoundland Power's electricity system assets increased by approximately 2 years.[15] In addition, during this period, Newfoundland Power invested approximately $203 million in its electricity system.[16]

15 In 2010, the average age of the Company's electricity system assets was 27.25 years. In 2014, the average age of the Company's electricity system assets is forecast to be 29.32 years.

16 In 2010, the installed value of Newfoundland Power's electrical system was approximately $1.182 billion. In 2014, the installed value of the Company's electricity system is forecast to be $1.385 billion. Electricity system assets exclude investments in information technology, transportation and general property.

Graph 2-3 shows Newfoundland Power's annual maintenance costs as a percentage of the installed value of its electricity system assets, as well as the average age of these assets from 2010 to 2014F.

Graph 2-3
Electricity System
Maintenance Costs and Average Age
2010 to 2014F



From 2010 to 2014F, the average age of the Company's electricity system assets is forecast to increase from approximately 27 years to approximately 29 years. During this period, the cost of maintaining the electricity system is forecast to decrease from 1.56% to 1.36% of the installed value of the system. This illustrates the efficiency of the Company's electricity system operating maintenance over this period.

In field operations, the Company has implemented work scheduling software to improve scheduling of planned and unplanned work. Integration of multiple systems, such as those containing geographic location and system connectivity information, eliminates manual processes and improves accessibility of information for employees. Initiatives such as these contribute primarily to capital cost efficiency in the maintenance of Newfoundland Power's electricity system.

Technology also contributes to operating efficiency in customer service. For example, the ongoing deployment of automated meter reading (AMR) meters reduces meter reading costs and the increasing customer participation in *eBills* reduces the cost of billing.

Conclusion

Quarterly customer surveys indicate that service reliability and price are the most important attributes of electrical service for Newfoundland Power's customers.

Excluding the effects of severe weather events, Newfoundland Power's electricity system reliability has been stable over the last 5 years. Newfoundland Power has also responded reasonably to customers' evolving service preferences, including their preference for more diverse electronic means of communicating with the Company.

Newfoundland Power's operating costs indicate reasonable and sustainable efficiency in customer operations.

2.2.2 Conservation Programming

Newfoundland Power's customer energy conservation programming is intended to be responsive to customers' desire to lower their electricity bills.

For the period 2009 to 2012, Newfoundland Power's customer energy conservation programs are expected to yield approximately 58.2 GWh in cumulative gross customer energy savings. Both customer participation in programming and general interest in conservation have increased during this period.

During the 2013 and 2014 test period, the Company will materially increase its expenditure on customer energy conservation programs. Beginning in 2013, the Company plans to expand its customer energy conservation program portfolio. This, together with the programming from 2009 to 2012, is expected to yield approximately 144.4 GWh in cumulative gross customer energy savings by the end of 2014.

At the current fuel forecast, avoided Holyrood production costs resulting from Newfoundland Power conservation efforts are expected to be approximately $9.4 million annually by year end 2014.

Background

Newfoundland Power customers have indicated that they are motivated to conserve principally to lower their electricity bills.[17] Newfoundland Power customer energy conservation programs are intended to be responsive to this.

[17] In the first quarter 2012, 96% of provincial electricity consumers indicated the primary motivation for trying to cut back on electricity use is to save money or lower their bill. This is an increase from 85% in 2010 and 89% in 2009.

In 2008, Newfoundland Power and Hydro developed a joint plan to implement a portfolio of customer energy conservation programs.[18] In 2009, Newfoundland Power implemented the residential and commercial customer energy conservation programs indicated in this plan.[19]

Table 2-7 shows customer participation, energy savings and costs for Newfoundland Power's customer energy conservation programs from 2009 to 2012F.

Table 2-7
Energy Conservation Programs
2009 to 2012F

	2009	**2010**	**2011**	**2012F**	**Total**
Participants	2,168	3,330	6,530	5,243	**17,271**
Energy Savings (GWh)[20]	2.6	7.7	19.8	28.1	**58.2**
Costs ($000s)	2,148	2,929	3,841	3,084	**12,002**

Since 2009, there have been over 17,000 participants in Newfoundland Power's customer energy conservation programs. General customer interest in conservation has also increased in this period. Visits to the *takeCHARGE!* website increased by almost 50%.[21]

[18] The *Five-Year Energy Conservation Plan: 2008 – 2013* was considered by the Board in Newfoundland Power's *2009 Conservation Cost Deferral Application* which resulted in Order No. P.U. 13 (2009).

[19] Newfoundland Power's customer energy conservation programs provide incentives to customers to reduce energy usage by installation of efficient technologies such as *Energy Star* windows.

[20] The energy savings indicated represent *gross* energy savings achieved by customers in each year. These savings reflect all technologies installed by participating customers since program implementation. *Net* energy savings would reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings; and (ii) program *free ridership* (an estimate of participants who would have chosen the more efficient product without the program). *Net* energy savings from 2009 to 2012F are estimated to be 37.6 GWh.

[21] In promotion of customer energy conservation, Newfoundland Power and Hydro chose to channel customer contact toward electronic means, particularly the *takeCHARGE!* website. This was motivated in large part by cost efficiency in program delivery. The number of visits to the joint *takeCHARGE!* website *increased* from 49,648 in 2009 to 72,996 in 2011((72,996 - 49,648) ÷ 49,648 = 0.47). By contrast, the number of Contact Centre inquiries regarding energy conservation *decreased* from 14,823 in 2009 to 12,624 in 2011, a decrease of approximately 15% ((14,823 - 12,624) ÷ 14,823 = 0.15).

From 2009 to 2012F, the annualized energy saved by Newfoundland Power customers grew from 2.6 GWh in 2009 to 28.1 GWh in 2012. The energy savings achieved by Newfoundland Power's 2009 expansion of customer energy conservation programming exceeded forecast savings.[22] At the currently forecast Holyrood fuel price of 18.9¢/kWh, energy savings of 28.1 GWh annually translates into avoided fuel costs of approximately $5.3 million annually.[23]

From 2009 to 2012, Newfoundland Power's total customer energy conservation costs have averaged approximately $3 million annually.[24]

Conservation Program Expansion

Newfoundland Power and Hydro recently reassessed the portfolio of customer energy conservation programs in light of experience since 2009.[25] This resulted in the creation of the *Five-Year Energy Conservation Plan: 2012 – 2016.*

The *Five-Year Energy Conservation Plan: 2012 - 2016* is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 1.*

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22 In the *2009 Conservation Cost Deferral Application*, it was estimated that Newfoundland Power's portion of *net* energy savings resulting from the *Five-Year Energy Conservation Plan: 2008 – 2013* would be approximately 15.1 GWh in 2012 (see *2009 Conservation Cost Deferral Application,* Prefiled Evidence, Table 1, page 12 for forecast provincial total net energy savings). *Net* energy savings achieved from the Company's customer energy conservation programs is forecast to be 19.6 GWh in 2012.

23 Hydro's Holyrood thermal generating station is typically the marginal production facility on the island grid. The cost of fuel associated with electricity generated at Holyrood is currently estimated at $0.189/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast of $118.80/barrel for 2012 as reflected in the Rate Stabilization Plan (28,100,000 kWh X $0.189 = $5,310,900).

24 Year to year differences in the composition of overall customer energy conservation costs principally reflect differences in program promotion and customer incentives. For example, costs related to program promotion and customer incentives were $3,041,000 in 2011, compared to $2,095,000 in 2010.

25 This reassessment was specifically envisaged in the *Five-Year Energy Conservation Plan: 2008 – 2013* (see page 8).

The principal changes contained in the *Five-Year Energy Conservation Plan: 2012 – 2016* relate to (i) discontinuation of certain residential incentives for new construction;[26] (ii) introduction of new residential customer programs;[27] and (iii) expansion of commercial customer programs.[28] Newfoundland Power expects to implement these changes in the 2013 and 2014 test period.

Table 2-8 shows forecast energy savings for Newfoundland Power's customer energy conservation programs from 2009 to 2014F.

Table 2-8
Forecast Energy Savings
Energy Conservation Programs
2009 to 2014F
(GWh)

	2009-2012F	**2013F**	**2014F**	**Total**
Residential	51.7	31.5	41.1	**124.3**
Commercial	6.5	5.2	8.4	**20.1**
Total	**58.2**	**36.7**	**49.5**	**144.4**

In 2014, the Newfoundland Power customer energy conservation program portfolio is forecast to achieve approximately 49.5 GWh in annual gross customer energy savings.[29] From 2009 to

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26 In 2013, changes to the National Building Code of Canada, Part 9, are expected to make basement insulation and energy efficient windows mandatory for new residential construction. As a result, the Company intends to discontinue provision of incentives for minimum building code compliance in new residential construction.

27 In 2013, the Company intends to develop and offer an incentive for the installation of high efficiency heat recovery ventilators ("HRVs") by residential customers. In 2014, the Company intends to offer coupon based incentives for smaller energy efficient technologies, such as specialty lighting products and household appliances, for residential customers. See the *Five-Year Energy Conservation Plan: 2012 - 2016, Volume 2, Exhibits & Supporting Materials, Reports, Tab 1* (pages 17-19).

28 In 2013, the Company intends to expand the existing commercial lighting program and to develop and offer a customized program for commercial customers that tailors incentives to site-specific energy saving opportunities. See the *Five-Year Energy Conservation Plan: 2012 - 2016, Volume 2, Exhibits & Supporting Materials, Reports, Tab1* (pages 17-19).

29 For 2013 and 2014, additional gross customer energy savings of approximately 10.7 GWh per year are forecast. ((49.5 GWh – 28.1 GWh) ÷ 2=10.7 GWh).

2014, the cumulative gross customer energy savings are forecast to be approximately 144.4 GWh.[30]

Table 2-9 shows forecast customer energy conservation costs for Newfoundland Power for 2009 to 2014F.

Table 2-9
Forecast Costs
Customer Energy Conservation
2009 to 2014F
($000s)

	2009-2012F	2013F	2014F
General	3,081	1,026	1,088
Program	8,921	3,065	4,401
Total	**12,002**	**4,091**	**5,489**

For 2013 and 2014, total customer energy conservation costs are forecast to average approximately $4.8 million per year. This compares to average annual costs of approximately $3 million from 2009 to 2012F. The increase in the Company's total customer energy conservation costs primarily reflects the expansion of customer energy conservation program offerings,[31] as well as additional market research and customer education and support activities.[32] In addition, in 2014, the Company intends to conclude a new conservation potential study to

30 The cumulative *net* energy savings are estimated to be 95.9 GWh for the period 2009 to 2014.

31 In 2013, increased customer energy conservation program costs include: (i) a new residential HRV program ($300,000); (ii) development of the coupon based program for smaller residential energy efficient technologies to be offered in 2014 ($118,000); (iii) expansion of the existing commercial lighting program ($144,000); (iv) a new customized program for commercial customers ($318,000); and (v) conservation potential study development ($94,000). In 2014, increased customer energy conservation program costs include: (i) implementation of the coupon based program for smaller energy efficient technologies ($1.5 million); (ii) continuation of the customized program for commercial customers ($491,000); and (iii) conclusion of the conservation potential study ($281,000). These increases in 2013 and 2014 are partially offset by cost reductions due to discontinuation of incentives for minimum building code compliance in new home construction.

32 In 2013, increased general conservation costs primarily reflect additional market research regarding customer energy end-uses and developments in air-to-air heat pump technology ($115,000).

identify new technologies and assess energy saving opportunities with a view to ensuring the continued effectiveness of Newfoundland Power's overall conservation efforts.[33]

Conclusion

From 2009 to 2012, Newfoundland Power expects to spend approximately $12 million related to customer energy conservation. Enduring gross customer energy savings of 28.1 GWh annually from 2012 are expected as a result.

In the 2013 and 2014 test period, Newfoundland Power forecasts costs of approximately $9.6 million related to customer energy conservation. This is expected to result in an additional 21.4 GWh in annual gross customer energy savings. Enduring gross customer energy savings of 49.5 GWh annually are expected by year end 2014F.

At the currently forecast Holyrood fuel price of 18.9¢/kWh, annual energy savings of 49.5 GWh translates into approximately $9.4 million annually in avoided fuel costs.[34]

2.2.3 Workforce Management

Newfoundland Power's workforce management is focused on maintaining the necessary skills to ensure continuity in the provision of safe, reliable service to its customers on a least cost basis.

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[33] This study is expected to be completed jointly with Hydro over 2013 and 2014 at a total cost to Newfoundland Power of approximately $375,000 (including approximately $94,000 in 2013 and $281,000 in 2014 program costs). The last conservation potential study for the island grid was completed in 2008.

[34] Based upon a 630 kWh/barrel conversion efficiency and oil price forecast of $118.80/barrel for 2012 as reflected in the Rate Stabilization Plan (49,500,000 kWh X $0.189 = $9,362,304).

The number of employees has not materially changed from that forecast at the Newfoundland Power 2010 General Rate Application. Overall labour costs remain consistent with the least cost delivery of service over both the short and long term.

General

Newfoundland Power relies on a highly skilled workforce to provide safe, reliable service to its customers at the lowest reasonable cost. In managing its workforce, the Company's primary considerations are matching overall capacity and capability with anticipated work requirements.[35] As well, the Company must consider factors such as workforce demographics; a changing labour market; and, evolving customer expectations, particularly regarding energy conservation.

Newfoundland Power's *Labour Forecast 2012-2014* is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 2*.

Workforce Demographics

Table 2-10 shows Newfoundland Power employee retirements and forecast retirements from 2010 to 2014F.[36]

Table 2-10
Employee Retirements
2010 to 2014F

2010	2011	2012F	2013F	2014F
8	23	30	19	25

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35 In fulfilling its capital and operating work requirements, the Company utilizes its regular workforce, its temporary work force, and contractors, depending on the nature and timing of the work requirements.

36 Employee retirement at Newfoundland Power is determined by the employee, not the Company. Accordingly, all forecasts are estimates of future retirements which are subject to change depending on each employee's specific personal circumstances.

In 2011 and 2012F, the number of employee retirements has been materially higher than experienced in recent years.[37] This higher level of retirements is expected to continue through the forecast period. From 2010 to 2014, a total of 105 retirements is forecast. The Company anticipated an increased level of employee retirements and is undertaking employee recruitment, retention, and development measures in order to maintain the required level of core skills in its workforce.[38]

The higher level of employee turnover, primarily due to retirements, impacts the composition of the Company's workforce. For example, while approximately 29% of Newfoundland Power's workforce has 30 years or more of service, another 26% of its workforce has less than 5 years of service.[39]

Labour Market Changes

Due to the rebounding economy and the demand for highly skilled employees, many companies are experiencing recruitment and retention issues.[40] Newfoundland Power has taken a number of measures to address these changes in the labour market.

For example, the Company has adapted its approach to hiring Powerline Technicians ("PLTs"). As expected, this skilled trade group is affected by the increasing number of retirements.

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[37] Newfoundland Power has not experienced this level of employee retirement activity since it offered early retirement programs, such as that in 2005 which resulted in 76 retirements. The actual number of retirements was lower than forecast in 2010, likely due to the economic conditions at that time.

[38] For example, the Company hired 42 regular employees in 2011, and 35 from January through July 2012. To support employee development and retention, Newfoundland Power has, for example, expanded its orientation program for new employees, and assessed technical skill requirements for Technologists and Engineers resulting in the implementation of individual development plans as required.

[39] Currently, the average age of Newfoundland Power's workforce is approximately 46 years.

[40] The Conference Board of Canada conducted a survey during the summer of 2011 and reported approximately 67% of companies in the private sector are having difficulty recruiting and retaining employees. See Conference Board of Canada, *Compensation Planning Outlook 2012*, October, 2011.

Newfoundland Power has historically hired a mix of Journeypersons and Apprentice PLTs. However, there has been limited availability of fully qualified Journeypersons in the labour market, particularly in 2011. To maintain continuity of the workforce and continued service reliability to customers, additional Apprentices are being hired in advance of the anticipated retirements of Journeypersons to allow a smooth transition of knowledge and job skills.[41]

Table 2-11 shows the number of Powerline Technicians employed by Newfoundland Power at year end 2010 to 2014F.

Table 2-11
Powerline Technicians
2010 to 2014F

	2010	**2011**	**2012F**	**2013F**	**2014F**
Journeypersons	118	124	119	115	115
Apprentices	30	30	35	38	38
Total	**148**	**154**	**154**	**153**	**153**

The Company's overall complement of Powerline Technicians is increasing by approximately 5 from 2010 to 2014F. Through this period, an increasing proportion of this complement will be Apprentices.[42] The increased employment of Apprentices is one of the ways the Company is dealing with retirements and a competitive labour market for skilled trades.[43] However, employment of a greater proportion of Apprentices will tend to increase the supervisory

41 The Apprenticeship Powerline Technician program provides for 5 years of education and training to achieve Journeyperson qualification. However, full development of a Powerline Technician typically requires more experience. For example, the *International Brotherhood of Electrical Workers* has observed it takes 10 years to become a well-rounded Powerline Technician.

42 By the end of 2014, Apprentices will comprise 25% of the Powerline Technician group. This represents an increase from 2010, when Apprentices comprised approximately 20% of the group.

43 Other ways include Newfoundland Power's implementation of an Apprentice PLT training site in Clarenville in addition to the site in St. John's. In addition, effective with the 2012 collective agreement, Apprentice PLTs are now considered regular employees as opposed to temporary during their apprenticeship period.

requirements associated with the development of Apprentice PLTs.[44] While required to ensure safe operations and service reliability to customers, this tends to add costs.[45]

Workforce Capacity

Table 2-12 shows Newfoundland Power's workforce as expressed in full time equivalents ("FTEs") for the period 2010 to 2014F.

Table 2-12
Workforce
Full Time Equivalents (FTEs)
2010 to 2014F

	2010	**2011**	**2012F**	**2013F**	**2014F**
Regular	572	572	588	604	607
Temporary	69	68	63	50	50
Total	**641**	**640**	**651**	**654**	**657**

From 2010 to 2014, Newfoundland Power's workforce is forecast to increase by 2.5% or 16 FTEs. There are two primary reasons for this increase. The first is Newfoundland Power's management of the ongoing demographic transition in its workforce. The second is Newfoundland Power's response to customer expectations regarding expansion of customer energy conservation programming.

In 2010 and 2011, FTEs were lower than forecast principally as a result of a higher number of

[44] The work performed by the Company's PLTs is predominately distribution capital and operating work. Therefore, increased costs associated with PLT development will tend to be reflected in distribution capital and operating costs. At *Newfoundland Power's 2010 General Rate Application*, the increased operating labour cost associated with increased Apprentice PLTs was calculated to be $140,000 in 2009 and $130,000 in 2010 (see Responses to Requests for Information CA-NP-111 and CA-NP-112).

[45] These costs are only partially offset by differences in compensation rates between Journeyperson and Apprentice PLTs.

resignations, retirements and leaves.[46] In 2012, the Company forecasts increased FTEs for PLTs, hiring of contract labour and regulatory requirements.[47] The increase in regular employment in 2012 reflects the agreement to treat Apprentice PLTs as regular employees.[48] In 2013 and 2014, the Company expects to increase its workforce by 4 FTEs to support the expansion of customer energy conservation programming and to increase its workforce by 2 FTEs related to PLT Apprenticeship.

Conclusion

An increase in FTEs related to the management of demographics is expected to be transitional in nature. To effectively accommodate increased replacement requirements, a greater total number of Journeyperson and Apprentice PLTs will be practically necessary.[49]

Expanded customer energy conservation programming will result in reduced electricity supply costs being incurred by Hydro. This, in turn, will serve to reduce customers' electricity bills from what they would otherwise be.

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[46] In the 4th quarter of 2009 and in 2010, the Company had 8 resignations/terminations which were not included in the 2009 and 2010 labour forecast. In addition, actual leaves for reasons, such as maternity and workers' compensation, were higher than forecast. These changes did not materially affect Newfoundland Power's costs in this period because the lower number of FTEs was effectively offset by a combination of contract labour, overtime and severance costs.

[47] The increase of approximately 7 FTEs for PLTs results from a combination of an increased number of Apprentice PLTs; an increased number of hours worked by Apprentice PLTs; the attainment of Journeyperson status by Apprentice PLTs; and the impact of 3 Journeyperson PLT hires in the 4th quarter of 2011. Two employees that previously served the Company on a contract basis were hired as regular employees in 2012 (contract employees are not included in Company FTE calculations). Increased regulatory requirements in 2012 have increased temporary labour requirement by approximately 1 FTE.

[48] In the collective agreement of May 18, 2012, between the Company and IBEW Local 1620, it was agreed that Apprentice PLTs which have historically been treated as temporary employees would be treated as regular employees. The proportion of regular and temporary employees in 2013 and 2014 are also affected by this change in status for Apprentice PLTs.

[49] Part of this practical requirement is the result of the relatively long 5 year Apprenticeship training requirement for PLTs. Part is the result of the fact that employees, not the Company, determine retirement dates.

Overall, Newfoundland Power's workforce management is expected to remain consistent with the least cost delivery of service to customers over both the short and long term.[50]

2.3 2013 AND 2014 OPERATING AND CAPITAL COSTS

The Board must consider Newfoundland Power's forecast 2013 and 2014 operating and capital costs in order to establish customer rates for this period.

This section of the evidence provides a review of Newfoundland Power's operating and capital costs forecast for 2013 and 2014 and includes an analysis of material cost changes from 2010 to 2014F.

Overall, Newfoundland Power's operating costs reflect improved labour productivity of approximately 1% per year.

2.3.1 Gross Operating Costs

General

Gross operating costs represent approximately 10% of the Company's forecast 2013 and 2014 revenue requirement.[51] Gross operating costs are those costs over which Newfoundland Power has the greatest degree of management control.

[50] Excluding the increased costs of the expansion of customer energy conservation programming, Newfoundland Power's inflation adjusted operating cost per customer is forecast to decrease from 2010 to 2014 (see Table 2-5, page 2-9). Overall, Newfoundland Power's operating labour costs are forecast to be approximately 1% less than forecast labour inflation for 2013 and 2014 (see Table 2-19, page 2-30).

[51] See Table 3-11 at page 3-23.

Table 2-13 shows Newfoundland Power's gross operating costs from 2010 to 2014F.

Table 2-13
Gross Operating Costs
2010 to 2014F
($000s)

2010	2011	2012F	2013F	2014F
53,542	57,207	57,223	59,145	62,043

Total gross operating costs for 2014 are forecast to increase by approximately 16% over 2010.

To gain an understanding of Newfoundland Power's gross operating costs, an examination of the costs by function and breakdown classification is required.

Classification by function focuses on the underlying reason for incurring a cost. Classification by breakdown focuses on the nature of the cost. For example, the Company classifies the salary of a Meter Reader in the Customer Relations Department in two ways: (i) by function, as a customer service cost; and (ii) by breakdown, as a labour cost.

Exhibits 1 and 2 show the Company's gross operating costs from 2010 to 2014F by function and by breakdown, respectively.

By Function

Table 2-14 summarizes operating costs by three functional categories: electricity supply, customer services and general for 2010 to 2014F.[52]

Table 2-14
Operating Costs by Function
2010 to 2014F
($000s)

Function	**2010**	**2011**	**2012F**	**2013F**	**2014F**
Electricity Supply	23,603	24,788	24,906	25,612	26,323
Customer Services	12,678	14,138	13,287	14,600	16,277
General	17,261	18,281	19,030	18,933	19,443
Total	**53,542**	**57,207**	**57,223**	**59,145**	**62,043**

Table 2-15 shows the operating costs associated with the electricity supply category broken out by function for 2010 to 2014F.

Table 2-15
Operating Costs – Electricity Supply
2010 to 2014F
($000s)

Function	**2010**	**2011**	**2012F**	**2013F**	**2014F**
Distribution	8,603	8,689	8,303	8,484	8,744
Transmission	823	698	931	973	1,014
Substations	2,295	2,245	2,482	2,552	2,621
Power Produced	2,630	2,577	2,661	2,897	2,974
Administration & Engineering	5,931	7,051	6,976	7,097	7,285
Telecommunications	1,507	1,471	1,468	1,450	1,480
Environment	310	266	246	284	292
Fleet Operations & Maintenance	1,504	1,791	1,839	1,875	1,913
Electricity Supply	**23,603**	**24,788**	**24,906**	**25,612**	**26,323**

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

Electricity supply costs for 2014 are forecast to increase by 12%, or approximately $2.7 million, compared to 2010.

Electricity supply costs include electricity system operating and maintenance activity. Labour rate increases impact the costs in this function.[53] Increases in fleet operations and maintenance costs, which primarily reflect rising costs of fuel, are the largest increases in non-labour electricity supply costs.[54] Power produced operating costs reflect the additional cost to operate the fish passage at Rattling Brook.[55]

Table 2-16 shows costs associated with the customer services category broken out by function for 2010 to 2014F.

Table 2-16
Operating Costs – Customer Services
2010 to 2014F
($000s)

Function	**2010**	**2011**	**2012F**	**2013F**	**2014F**
Customer Services	8,948	9,093	9,307	9,613	9,873
Conservation	2,929	3,841	3,084	4,091	5,489
Uncollectible Bills	801	1,204	896	896	915
Customer Services	**12,678**	**14,138**	**13,287**	**14,600**	**16,277**

53 Electricity supply labour is forecast to increase from $14,309,048 in 2010 to $15,675,403 in 2014, or approximately 9.5% over the 4 year period. This compares to a composite labour rate increase of approximately 17.9% over the period.

54 Fleet operations costs are forecast to increase by $409,197 or approximately 27% from 2010 to 2014. Overall, non-labour electrical supply costs are forecast to increase from $9,294,592 in 2010 to $10,647,786 in 2014, a cumulative increase of approximately 14.6% over the 4 year period. Excluding the increase in fleet operations costs, the increase in non-labour electricity supply costs over the 4 year period was approximately 10.2% ((10,647,786 – 409,197) ÷ 9,294,592 = 1.102).

55 Commencing in 2013, the Company will spend an additional $125,000 per year related to Rattling Brook Fisheries Compensation. This expenditure is required to permit downstream migration of salmon kelts and smolts and the upstream migration of grilse and adult salmon.

Customer Services operating costs for 2014 are forecast to increase 28%, or approximately $3.6 million, compared to 2010. Conservation costs account for approximately $2.6 million of this increase.[56]

Table 2-17 shows costs associated with the general category broken out by function from 2010 to 2014F.

Table 2-17
Operating Cost – General
2010 to 2014F
($000s)

	2010	**2011**	**2012F**	**2013F**	**2014F**
Information Systems	2,813	2,939	3,000	3,089	3,168
Financial Services	1,677	1,815	1,712	1,765	1,849
Corporate & Employee Services	11,677	12,445	13,129	12,888	13,210
Insurances	1,094	1,082	1,189	1,191	1,216
Total	**17,261**	**18,281**	**19,030**	**18,933**	**19,443**

General operating costs are forecast to increase by approximately 13% or $2.2 million from 2010 to 2014. A primary source of this is the approximately $1.5 million increase in corporate and employee services costs. This reflects a number of factors. First, increased regulatory costs and higher assessment fees from the Board have contributed to the increase.[57] Second, increased labour costs associated with human resources over the period are required to deal with matters associated with workforce demographics, including increased levels of retirement, recruitment

[56] Conservation costs are outlined in detail in *Section 2.2.2 Conservation Programming*. Excluding the $2.6 million increase in conservation costs, overall customer services costs are forecast to increase by approximately 7.8% from 2010 to 2014.

[57] Increased regulatory costs include increased labour costs associated with regulatory activity and succession planning for regulatory affairs. This has increased regulatory labour costs by approximately $0.2 million per year. Non-labour costs associated with regulation include Board assessments and costs (including Board consultants and Consumer Advocate costs) typically associated with Company applications. In 2010, Board assessments and costs totalled approximately $0.9 million. In 2014, Board assessments and costs are forecast to total approximately $1.4 million. In aggregate, increased regulatory costs included in corporate and employee services from 2010 to 2014 are approximately $0.7 million.

and training.[58] Thirdly, these increases are partially offset by lower severance and retirement costs since 2010.[59] Insurance costs reflect higher premiums primarily related to growth in the Company's asset base.

By Breakdown

The primary breakdown categories of Newfoundland Power's operating costs are labour costs and other, non-labour, costs.

Table 2-18 shows the breakdown of operating costs from 2010 to 2014F.

Table 2-18
Operating Cost by Breakdown
2010 to 2014F
($000s)

	2010	**2011**	**2012F**	**2013F**	**2014F**
Labour	31,233	32,951	32,996	34,064	35,421
Other	22,309	24,256	24,227	25,081	26,622
Total	**53,542**	**57,207**	**57,223**	**59,145**	**62,043**

In 2013 and 2014, labour costs are forecast to represent approximately 58% and 57% respectively of the Company's gross operating costs. This is consistent with recent experience.

Newfoundland Power's labour costs are forecast to increase by an average of 3.2% annually from 2010 to 2014. This increase is approximately 1% lower per year than the Company's

[58] In 2014, human resources labour costs included in corporate and employee services are forecast to be approximately $1.35 million compared to approximately $0.95 million in 2010.

[59] In 2010, the Company incurred $500,000 in employee severance which was accounted for in the corporate and employee service class. For 2014, the Company has forecast approximately $100,000 in employee severance costs. Commencing in 2011, the Company adopted accrual accounting for OPEBs costs (see Order No. P.U. 31 (2010)). Retirement allowances are now included in the accruals for OPEBs.

average labour rate increase over this period.[60] Labour rate increases, expansion of customer energy conservation programs, and response to changing workforce demographics are the primary drivers of the increases in labour costs.

Other costs for 2014 are forecast to increase by approximately 19%, or $4.3 million compared to 2010. Customer energy conservation costs account for approximately $2 million of this increase.[61] Inflationary increases are responsible for much of the remaining increase through this period, including increased vehicle expenses of approximately $0.4 million which reflect the increased cost of fuel. There are also a number of increases which reflect specific cost changes.[62]

Table 2-19 shows the breakdown of labour costs from 2010 to 2014F.

Table 2-19
Labour Cost by Breakdown
2010 to 2014F
($000s)

	2010	**2011**	**2012F**	**2013F**	**2014F**
Regular and Standby	26,568	28,376	28,505	29,791	31,023
Temporary	1,917	2,320	2,583	2,365	2,433
Overtime	2,748	2,255	1,908	1,908	1,965
Total	**31,233**	**32,951**	**32,996**	**34,064**	**35,421**

[60] The Company's composite labour rate increase from 2010 to 2014F is 4.20% per year.

[61] The $2 million includes increased general conservation and program costs. Conservation incentives to customers alone account for $1.1 million of the increase. Other significant components of the $2 million increase include an increase of approximately $0.4 million in other company fees associated with the conservation potential and customer end-use studies and an increase of approximately $0.3 million in advertising.

[62] These include an increase in the Board assessment of approximately $0.3 million from 2010 through 2014. They also include an increase in operating materials of approximately $0.45 million which, in part, reflects new contracting arrangements regarding streetlight maintenance in the Northeast Avalon.

Total labour costs from 2010 to 2014 are forecast to increase by approximately 13% or $4.2 million. This reflects an average increase in operating labour of approximately 3.2% per year. This compares to labour *rate* increases agreed to by the Company and its unionized employees of approximately 4.2% per year from 2010 to 2014.[63] This represents overall labour productivity of approximately 1% per year.

Regular and standby labour costs to 2014 are forecast to increase by approximately 17%, or $4.5 million, compared to 2010. This increase includes the impact of annual labour rate increases,[64] additional conservation related costs,[65] as well as a change in employment status for Apprentice Power Line Technicians from temporary to regular beginning in 2012.

Temporary labour costs for 2014 are forecast to increase by approximately 27%, or $500,000, compared to 2010. This reflects annual labour rate increases, as well as the Company's utilization of temporary employees to maintain customer service levels through the ongoing workforce transition.[66]

Overtime labour costs for 2014 are forecast to decrease by approximately 28%, or $800,000, compared to 2010. In 2010, overtime costs were increased as a result of severe weather events.

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63 The Company's composite corporate labour rate (union and management) increase is 4.20% per year for the period.

64 The weighted labour cost increases agreed to between the Company and its union were 5.4% in 2011; 3.02% in 2012; 4.36% in 2013; and 4.25% in 2014. This is an average annual increase of 4.26% for the period 2010 to 2014F.

65 The increase in labour cost associated with the Company's customer energy conservation program initiatives from 2010 to 2014 is approximately $0.6 million. Approximately $0.4 million of this is associated with the forecast expanded customer energy conservation programming portfolio. Excluding the cost increase associated with the forecast expanded portfolio, the increase in average annual Newfoundland Power labour costs for 2010 to 2014 is approximately 2.9%.

66 For example, the Company typically utilizes temporary employees to backfill attrition of regular employees in Meter Reader and Customer Account Representative positions. This provides flexibility in managing overall workforce size.

2.3.2 Capital Costs

Newfoundland Power's annual capital budget reflects a large number of assets needed to support the electrical system that is spread over a broad geographic area.

Table 2-20 shows capital expenditures from 2010 to 2014F.

Table 2-20
Capital Expenditures
2010 to 2014F
($000s)

	2010	2011	2012F[67]	2013F	2014F
Generation	5,162	8,828	8,439	4,734	9,030
Substations	9,564	11,980	13,576	17,618	15,354
Transmission	3,139	5,261	5,877	5,371	5,483
Distribution	39,175	38,210	40,182	38,740	39,533
General Property	1,320	1,757	1,651	1,737	2,315
Transportation	2,287	2,272	2,306	2,950	2,690
Telecommunications	325	109	175	874	69
Information Systems	3,393	3,699	3,680	4,014	3,994
Unforeseen Allowance	5,899[68]	305	750	750	750
General Expenses Capitalized ("GEC")	3,316	3,750	4,000	4,000	4,000
Total	**73,580**	**76,171**	**80,636**	**80,788**	**83,218**

Total capital expenditures from 2010 to 2014 are forecast to increase principally as the result of inflation. Forecast expenditures by asset class are broadly consistent with recent experience, with the exception of generation and substations which vary annually due to refurbishment and system load growth requirements.

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67 The Company's *2012 Capital Budget Application* was approved in Order No. P.U. 26 (2011). Forecast 2012 expenditures also include approximately $1.335 million in projects carried forward from 2011 and supplemental capital expenditures approved in Order Nos. P.U. 7 (2012) and P.U. 8 (2012) which relate to the upgrade of MIL-02 feeder and the repair of the Bell Island submarine cable.

68 Unforeseen Allowance expenditures in 2010 include costs associated with system restoration following Hurricane Igor in September and an ice storm in March.

SECTION 3: FINANCE

3.1 OVERVIEW

Sound financial management is critical to Newfoundland Power's long term ability to deliver safe, reliable electrical service to its customers on a least cost basis. For this reason, the continued financial integrity of Newfoundland Power benefits both the Company and its customers.

Newfoundland Power's financial performance through 2012 is expected to be consistent with the maintenance of its financial integrity. For 2013 and 2014, the Company's financial performance under existing customer rates is not expected to be consistent with the maintenance of its financial integrity.

A central issue in this Application is Newfoundland Power's cost of capital for 2013 and 2014 and, in particular, the determination of a fair return on equity for the Company. The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2013 and 2014 is 10.4% to 10.5%.

Another central issue in this Application is the future of the Formula. The Company is proposing that the Formula be discontinued given current financial market conditions.

In this Application, Newfoundland Power is proposing regulatory accounting changes related to depreciation expense, pension expense, customer energy conservation program costs, and the Weather Normalization Reserve. In total, these proposals will reduce the Company's

revenue requirements by approximately $2.9 million in 2013 and approximately $4.2 million in 2014.

Newfoundland Power is also proposing three year amortizations for (i) certain existing deferred balances; (ii) third party hearing costs; and (iii) the forecast 2013 revenue shortfall associated with this Application. In total, these proposals will reduce the Company's revenue requirements by approximately $0.2 million in 2013 and increase revenue requirements by approximately $0.8 million in 2014.

3.2 FINANCIAL PERFORMANCE: 2010 TO 2014

Sound financial performance is essential to the financial integrity necessary to ensure Newfoundland Power's ability to deliver least cost reliable electrical service over the long term.

This section of the evidence reviews the Company's actual financial performance for 2010 and 2011 and its forecast financial performance for 2012, 2013 and 2014 under existing customer rates. Exhibit 3 in Volume 2, Exhibits & Supporting Materials, shows the detail of Newfoundland Power's actual financial performance for 2010 and 2011 and forecast financial performance for 2012, 2013 and 2014 based on existing customer rates which exclude the effects of proposals made in this Application.

For the period 2010 to 2012F, Newfoundland Power's financial performance will have been consistent with the continued financial integrity of the Company.

For 2013 and 2014, forecast financial performance under existing customer rates will not be consistent with the maintenance of Newfoundland Power's long term financial integrity.

3.2.1 Revenue

Electricity Rate Revenue

Table 3-1 shows electricity sales and revenue from 2010 to 2014E.[1]

Table 3-1
Electricity Sales and Revenue
2010 to 2014E

	2010	**2011**	**2012F**	**2013E**	**2014E**
Electricity Sales					
Electricity Sales (GWh)	5,419	5,553	5,681	5,776	5,893
Sales Growth (%)	2.3	2.5	2.3	1.7	2.0
Electricity Revenue ($000s)					
Revenue from Rates	535,333	552,558	564,349	573,733	584,639
2005 Unbilled Revenue[2]	4,618	-	-	-	-
RSA Transfers[3]	1,573	10,049	15,342	19,786	23,170
Total Electricity Revenue	**541,524**	**562,607**	**579,691**	**593,519**	**607,809**

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

[1] References to 2013 and 2014 with the notation 'E' (i.e., 2013E) are intended to indicate forecast results under existing customer rates which exclude the effects of the proposals contained in this Application. The 2013E and 2014E forecast includes the effects of continuing with current customer rates approved in Order No. P.U. 32 (2010) which effectively include a forecast cost of common equity of 8.38% for rate setting purposes.

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

[3] RSA transfers reflect actual and forecast operation of the Energy Supply Cost Variance clause approved in Order No. P.U. 32 (2007); the Pension Expense Variance Deferral Account approved in Order No. P.U. 43 (2009); the Other Post-Employment Benefits Cost Variance Deferral Account approved in Order No. P.U. 31 (2010); and transfers related to revenue effects of implementation of a Domestic Seasonal Optional Rate as approved in Order No. P.U. 8 (2011).

Electricity sales growth in 2010 and 2011 was 2.3% and 2.5%, respectively. Sales growth for 2012 is forecast to be 2.3%. Under existing customer rates, 2013 sales growth is forecast to moderate to 1.7% and 2014 is forecast to be 2.0%.[4] Electricity sales growth from 2010 to 2014E reflects increases in the number of customers served by Newfoundland Power, and a continuing high proportion of electric heating in new home construction.[5]

Forecast electricity sales and electricity revenue for 2012, 2013E and 2014E are based on the Company's August 2012 sales forecast.[6]

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4 The number of customers served by Newfoundland Power is forecast to increase by approximately 1.3% in each of 2013 and 2014. If the rate increase proposed in this Application is approved by the Board, the 2013 and 2014 forecast sales growth will be reduced from 1.7% to 1.2% and 2.0% to 1.2% respectively. This is a result of elasticity effects or the dynamic of increasing price reducing consumption. See *Section 5.2 Customer, Energy and Demand Forecast*, page 5-2 to page 5-5.

5 The proportion of new housing using electric heating was 90% in 2010 and 88% in 2011; and is forecast to be 88% in 2012, 86% in 2013 and 88% in 2014.

6 The *Customer, Energy, and Demand Forecast* of August 2012 is found in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 4.*

Other Revenue

Table 3-2 shows other revenue from 2010 to 2014E.

Table 3-2
Other Revenue
2010 to 2014E
($000s)

	2010	**2011**	**2012F**	**2013E**	**2014E**
Pole Attachment[7]	9,360	927	1,480	1,530	1,566
Bell Aliant – Joint Use Transition[8]	-	4,703	-	-	-
Bell Aliant Pole Installations/Removals[9]	-	1,046	1,053	1,052	1,095
Amortization of Municipal Tax ("MTA") Liability [10]	1,363	-	-	-	-
Customer Account Interest	791	904	918	919	932
Interest on Rate Stabilization Account[11]	66	414	763	267	93
Miscellaneous[12]	1,846	2,011	2,044	1,662	1,654
Total	**13,426**	**10,005**	**6,258**	**5,430**	**5,340**

Since 2001, pole attachment revenues have been the largest component of Newfoundland Power's other revenue.[13] In 2011, as a result of new support structure arrangements between the Company and Bell Aliant Regional Communications Inc. ("Bell Aliant"), pole attachment

[7] Pole attachment revenues are forecast to increase in 2012 to 2014E due to increased rental revenues from third parties.

[8] As a transitionary measure between joint use regimes, Newfoundland Power performed the maintenance of Bell Aliant's support structure requirements throughout 2011 for approximately $1.4 million. In addition, Newfoundland Power also received reimbursement of carrying costs of approximately $3.3 million in 2011 on joint use poles ultimately transferred to Bell Aliant.

[9] Since 2011, Newfoundland Power provides Bell Aliant with pole installation and removal services on their joint use poles.

[10] The amortization of a legacy MTA liability was approved in Order No. P.U. 32 (2007).

[11] Year to year variances in interest on RSA reflects variations in year to year balances in the RSA.

[12] Miscellaneous revenue includes work done at customer request, wheeling charges and fees charged pursuant to the Company's regulations governing service. The forecast reduction in miscellaneous other revenue primarily reflects Bell Aliant's forecast conclusion of its fibre optic expansion on the northeast Avalon.

[13] In 2001, Newfoundland Power purchased all jointly used utility poles in its service territory that were owned by Bell Aliant (then, Aliant Telecom), subject to a right of repurchase. This purchase was approved by the Board in Order No. P.U. 17 (2001 – 2002). As a result of this purchase, Newfoundland Power's pole attachment rentals from Bell Aliant increased materially.

revenues decreased materially.[14]

Overall, Newfoundland Power's other revenue is expected to be stable in 2013 and 2014 at approximately $5.3 to $5.4 million per year.

3.2.2 Power Supply

Table 3-3 shows power supply cost from 2010 to 2014E.

Table 3-3
Power Supply Cost
2010 to 2014E
($000s)

	2010	2011	2012F	2013E	2014E
Purchases from Hydro (Normalized)	355,438	365,582	381,446	392,547	404,686
Replacement Energy Cost[15]	598	-	-	-	-
Weather Normalization Reserve[16]	2,101	2,101	2,101	-	-
DMI Account[17]	994	1,801	1,185	479	443
Unit Cost Variances[18]	(688)	-	-	-	-
Power Supply Cost	**358,443**	**369,484**	**384,732**	**393,026**	**405,129**

[14] On January 1, 2011, the new support structure arrangements with Bell Aliant went into effect. These new arrangements included Bell Aliant's repurchase of 40% of all joint use poles and related infrastructure from Newfoundland Power and the discontinuation of pole attachment rentals between the parties. The Board approved the repurchase in Order No. P.U. 21 (2011).

[15] In Order No. P.U. 39 (2006), the Board approved the deferred recovery of $1.8 million ($1.1 million on an after tax basis) in replacement energy costs related to the Rattling Brook Hydro Plant refurbishment project. In Order No. P.U. 32 (2007) the Board approved amortization over the period 2008 to 2010 of this deferral in equal amounts.

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

[17] The Demand Management Incentive ("DMI") account was approved by the Board in Order No. P.U. 32 (2007). In 2010, an amount of approximately $1.0 million reflecting reduced demand costs accrued to the DMI account. In Order No. P.U. 7 (2011), the Board approved refund of this amount to customers via the July 1, 2011 RSA adjustment. In 2011, an amount of approximately $1.8 million reflecting reduced demand costs accrued to the DMI account. In Order No. P.U. 9 (2012), the Board approved refund of this amount to customers via the July 1, 2012 RSA adjustment.

[18] In Order No. P.U. 32 (2007) the Board approved the amortization over the period 2008 to 2010 of a $2.1 million ($1.3 million on an after-tax basis) balance which had accrued in the legacy Purchased Power Unit Cost Reserve up to December 31, 2006.

Increases in power supply cost substantially reflect increased purchases from Hydro to meet Newfoundland Power's customers' requirements. Power supply costs also reflect amortizations approved by the Board.

3.2.3 Employee Future Benefits

General

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 ("OPEBs") plans.

Table 3-4 shows the Company's employee future benefits expense from 2010 to 2014E.

Table 3-4
Employee Future Benefits Expense
2010 to 2014E
($000s)

	2010	**2011**	**2012F**	**2013E**	**2014E**
Pension Expense	7,588	11,566	12,869	12,714	12,195
OPEBs Expense	793	9,003	9,300	10,461	10,436
Total Expense	**8,381**	**20,569**	**22,169**	**23,175**	**22,631**

The Company expects employee future benefits expense for 2013 and 2014 to be approximately $1 million and $0.5 million, respectively, higher than 2012.

Pensions

Newfoundland Power maintains both defined benefit and defined contribution pension plans.[19]

Table 3-5 shows Newfoundland Power's pension expense from 2010 to 2014E.

Table 3-5
Pension Expense
2010 to 2014E
($000s)

	2010	**2011**	**2012F**	**2013E**	**2014E**
Defined Contribution Pension Plans[20]	1,202	1,295	1,502	1,564	1,629
Defined Benefit Pension Plans[21]	6,386	10,271	11,367	11,150	10,566
Total Expense	**7,588**	**11,566**	**12,869**	**12,714**	**12,195**

In 2011, Newfoundland Power's pension expense increased by approximately $4.0 million to $11.6 million. This increase is primarily related to amortization of losses from prior years associated with the pension plan assets and a lower discount rate in 2011.[22] A decrease in discount rate serves to increase both pension and OPEBs expense.

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[19] Newfoundland Power's largest pension plan is its defined benefit pension plan which was created in 1984. There were 438 active employees participating in this plan as at December 31, 2011. In addition, at December 31, 2011 the defined benefit pension plan provided retirement income to a total of 661 retirees and their survivors. The defined benefit pension plan provides retirement income based upon an employee's pay and years of service at the time of retirement. Since May 2004, Newfoundland Power's defined benefit pension plan has been closed to new entrants. Since 2004, all new employees of Newfoundland Power participate in a defined contribution pension plan. The defined contribution pension plan provides retirement income based upon the contributions made by the Company and employee together with accrued returns on those contributions.

[20] Pension expense for Newfoundland Power's defined contribution pension plans reflects the Company's contributions in each year.

[21] 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.

[22] The increase related to amortization of losses from prior years was approximately $3.1 million. The increase related to a lower discount rate was approximately $1.0 million. The discount rate decreased from 6.50% in 2010 to 5.75% in 2011. The discount rate used to value pension obligations is prescribed by accounting standards.

Newfoundland Power's pension expense is expected to increase to $12.9 million in 2012 principally due to a further decline in the discount rate.[23] This increase is somewhat offset by an increase in pension plan assets.[24]

Compared to 2012F, pension expense for 2013E and 2014E is forecast to decrease by approximately $0.2 million and $0.7 million respectively. This is the result of a combination of higher forecast returns on pension plan assets and a lower forecast discount rate.[25]

OPEBs

Table 3-6 shows Newfoundland Power's OPEBs expense from 2010 to 2014E.

Table 3-6
OPEBs Expense
2010 to 2014E
($000s)

	2010[26]	**2011**	**2012F**	**2013E**	**2014E**
OPEBs Expense	793	9,003	9,300	10,461	10,436

Effective 2011, the Company changed its method of accounting for OPEBs expense from the cash basis to the accrual basis.[27]

[23] The discount rate decreased from 5.75% in 2011 to 5.25% in 2012.

[24] The increase in defined benefit pension plan assets is principally related to additional contributions made by the Company commencing in 2012. Newfoundland Power's defined benefit pension plans contributions for 2012 to 2014 are expected to increase based on a solvency deficiency of $49.5 million identified in a Defined Benefit Pension Plan Valuation dated December 31, 2011. This solvency deficit is being funded over a 5 year period by special solvency payments (inclusive of interest) of approximately $10.7 million annually.

[25] The forecast discount rate used to value the pension obligation and related pension expense in 2013 and 2014 is 4.90% and is based upon current market indications. The actual discount rate used to value pension obligation and related annual pension expense is determined as at December 31 of each year.

[26] In 2010, the OPEBs expense was recognized on the cash basis of accounting and was included in operating expenses.

[27] This was approved by the Board in Order No. P.U. 31 (2010).

OPEBs expense in 2012 is forecast to increase by approximately $0.3 million primarily as a result of a lower discount rate.[28] Compared to 2012, OPEBs expense for 2013 and 2014 is forecast to increase by approximately $1.2 million and $1.1 million respectively.

This is the result of a combination of a lower forecast discount rate and higher forecast OPEBs obligation.[29]

3.2.4 Depreciation

Table 3-7 shows depreciation and related cost recovery deferrals from 2010 to 2014E.

Table 3-7
Depreciation Expense
2010 to 2014E
($000s)

	2010	**2011**	**2012F**	**2013E**	**2014E**
Depreciation[30]	43,533	42,870	44,441	45,942	47,561
Depreciation True-up[31]	(175)	(175)	-	-	-
Amortization of Deferred Cost Recoveries[32]	3,862	-	-	-	-
Net Expense	**47,220**	**42,695**	**44,441**	**45,942**	**47,561**

28 The discount rate used to determine the OPEBs expense was 5.75% in 2011 and 5.25% in 2012.

29 The forecast discount rate for 2013 and 2014 is 4.90% and is based on current market indications. The actual discount rate used to value the OPEBs obligation and related annual OPEBs expense is determined as at December 31 of each year. The approximately $5.6 million increase in OPEBs obligation as at January 1, 2012 was determined by Mercer (Canada) Ltd., the Company's actuaries.

30 Newfoundland Power's depreciation expense reflects depreciation rates for 2010 and subsequent years, as approved by the Board in Order No. P.U. 32 (2007). In this Application, Newfoundland Power is proposing to change depreciation rates commencing in 2013. Depreciation expense as shown in Table 3-7 for 2013E and 2014E reflects depreciation rates approved in Order No. P.U. 32 (2007), not the depreciation rates proposed in this Application.

31 Newfoundland Power's depreciation expense for 2010 to 2011 is reduced by $175,000 annually as a result of a 4 year amortization beginning in 2008 of a depreciation true-up of approximately $0.7 million approved by the Board in Order No. P.U. 32 (2007).

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

Changes in net depreciation expense are a result of continued investment in the electricity system and Board orders related to true-ups and cost recoveries. Net depreciation expense decreased approximately $4.5 million from 2010 to 2011 as a result of a combination of (i) Board Orders related to true-ups and cost recoveries and (ii) a decrease in depreciable plant as a result of the sale of 40% of joint use poles to Bell Aliant.[33]

The forecast increase in depreciation expense from 2012F to 2014E, which is based upon current depreciation rates, relates to continued investment in the electricity system.

3.2.5 Finance Charges

Table 3-8 shows average debt, finance charges and average cost of debt for 2010 to 2014E.

Table 3-8
Finance Charges
2010 to 2014E

	2010	**2011**	**2012F**	**2013E**	**2014E**
Average Debt ($000s)	477,366	475,471	485,232	503,732	526,705
Finance Charges ($000s)	35,633	35,484	35,457	35,534	36,634
Average Cost of Debt (%)	7.46	7.46	7.31	7.05	6.96

Newfoundland Power's average debt consists of First Mortgage sinking fund bonds ("First Mortgage Bonds") and amounts outstanding under bank credit facilities.[34] The decrease in average debt from 2010 to 2011 is the result of Bell Aliant's repurchase of 40% of joint use

[33] The decrease in 2011 depreciation expense which resulted from the sale of 40% of joint use poles to Bell Aliant was approximately $2.5 million.

[34] Newfoundland Power's bank credit facilities are comprised of a $100 million committed revolving term facility and a $20 million demand facility. In June 2011, the committed facility was renegotiated with a decrease in pricing and an extension of maturity to August 2015. In March 2012, the committed facility was renegotiated with a further decrease in pricing and an extension of maturity to August 2017.

poles. Increases in average debt from 2011 to 2014E are principally due to continued investment in the electricity system required to provide service to customers.

Finance charges are the cost of debt used to finance investment in regulated assets. Finance charges are composed primarily of interest on First Mortgage Bonds and short term borrowings.[35]

Finance charges are relatively stable throughout the period 2010 to 2013E and are forecast to increase by approximately $1.1 million from 2013E to 2014E. This reflects the Company's financing plans.[36]

The average cost of debt from 2011 to 2014E is forecast to decline. This reflects lower interest rates and a higher proportion of short-term debt in the Company's average debt.

3.2.6 Income Taxes

Table 3-9 shows the Company's income taxes from 2010 to 2014E.[37]

Table 3-9
Income Taxes
2010 to 2014E

	2010	2011	2012F	2013E	2014E
Income Taxes ($000s)	16,814	16,261	13,902	13,102	12,327
Effective Income Tax Rate (%)	31.51	31.20	28.14	29.10	29.15

35 Finance charges also reflect amounts related to the amortization of debt issue costs, amortization of credit facility costs, and the interest portion of allowance for funds used during construction.

36 The Company plans a $75.0 million 5.25% First Mortgage Bond issue for the 1st quarter of 2014 to refinance short term borrowings and refund an existing $29.8 million 10.55% bond issue due July 2014.

37 Income taxes exclude the effect of non-regulated operating costs and allocation of the Part VI.1 tax deduction from Fortis Inc. to Newfoundland Power. These tax adjustments were $944,000 in 2010 and $385,000 in 2011. They are forecast to be $3,211,000 in 2012F, $582,000 in 2013E and $608,000 in 2014E.

Newfoundland Power's effective income tax rate changes from 2010 to 2014E principally due to reductions in the statutory income tax rate.[38]

The Company's effective income tax rates are forecast to remain stable through 2013E and 2014E.

3.2.7 Returns

Table 3-10 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 2010 to 2014E.

Table 3-10
Rates of Return
2010 to 2014E
(%)

	2010	**2011**	**2012F**	**2013E**	**2014E**
Return on Rate Base					
Midpoint (Approved)	8.23	7.96	8.14	-	-
Actual / Forecast	8.24	8.14	8.02	7.37	7.02
Return on Common Equity	9.21	9.00	8.81	7.57	6.89

Newfoundland Power's actual rate of return on rate base for 2010 was approximately at the midpoint used for rate setting purposes.[39]

Newfoundland Power's actual rate of return on rate base for 2011 was approximately 18 basis

[38] The statutory income tax rate was 32.0% in 2010, 30.5% in 2011 and forecast to be 29.0% for 2012F to 2014E. In 2011, income tax reflects a change in the Company's treatment of tax related to overtime banked by employees.

[39] Newfoundland Power's rate of return on rate base for 2010 was set in Order No. P.U. 46 (2009).

points (0.18%) above the midpoint.[40] The principal contributor to the higher rate of return on rate base was the revision of the terms for the shared use of utility poles and related infrastructure between Newfoundland Power and Bell Aliant.[41] The Company's rate of return on rate base for 2012 is forecast to be 12 basis points (0.12%) below the Board approved midpoint used for rate setting purposes.[42]

The forecast rates of return on rate base and equity for 2013E and 2014E reflect the eroding financial position of the Company which would result from continuation of current customer rates.

3.3 COST OF CAPITAL

In this Application, the Board will consider Newfoundland Power's cost of capital for 2013 and 2014. The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2013 and 2014 is 10.4% to 10.5%.

This section of the evidence reviews the more prominent elements of risk to which Newfoundland Power, as a business, is exposed. These risk elements have not changed materially over the past 5 years. Financial market conditions, on the other hand, have changed dramatically over this period.

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40 Newfoundland Power's rate of return on rate base for 2011 was set in Order No. P.U. 32 (2010).

41 On March 30, 2012, Newfoundland Power filed its *Report on the 2011 Regulated Rate of Return on Equity* with the Board as required by Order No. P.U. 19 (2003). This report explains in detail the circumstances and facts contributing to the Company's actual 2011 rate of return on equity.

42 Newfoundland Power's rate of return on rate base for 2012 was set by the Board in Order No. P.U. 17 (2012).

This section of the evidence also reviews the performance of the Formula since 2008. Since Newfoundland Power's last general rate application in 2009, the Formula has consistently indicated returns on equity for the Company which are materially lower than those earned by other investor owned electrical utilities. This is a reflection of unsettled financial market conditions and, in particular, declining Canada bond yields. In this Application, Newfoundland Power is proposing that the Formula should be discontinued as it does not accurately estimate a fair return on equity under current financial market conditions.

Finally, this section of the evidence reviews Newfoundland Power's credit metrics under existing and proposed customer rates. Proposed customer rates, which are based upon a return on equity of 10.4% for 2013 and 2014, are consistent with maintenance of the continued financial integrity of the Company.

3.3.1 Risk Assessment

General

Cost of capital is the rate of return that investors could expect to earn if they invested in equally risky securities.[43] Therefore, cost of capital is essentially a relative concept. The accepted relative measure for determining a business' cost of capital is risk.

Risk is an assessment of the capability of an enterprise to recover its investment as well as earn a return on that investment. For regulated utilities such as Newfoundland Power, risk is generally considered to have business, regulatory and financial elements.

[43] See, for example, Brealey, Myers et. al., *Fundamentals of Corporate Finance* (2nd Canadian Edition), page 271.

The business elements relate to the Company's operations and assets. Newfoundland Power principally invests in long-lived assets, which implies that risk assessment should be undertaken over long term horizons.[44] The regulatory elements relate to the regulatory framework under which the Company operates and the Board's determinations of how Newfoundland Power's costs are to be recovered and how risks are to be shared between investors and customers. The financial elements of risk principally relate to the degree that debt is used to finance the Company.

Cost of capital depends on all three elements of risk and how they compare to those of other enterprises, including other enterprises in the same industry. Regulated utilities are typically considered to be relatively low risk enterprises.

Relative to its Canadian utility peers, the Board has historically assessed Newfoundland Power to be an average risk Canadian utility.[45] Financial market conditions have changed dramatically in recent years. Newfoundland Power's principal business, regulatory and financial risks, however, have not changed materially over this time.

This portion of the Company's evidence assesses some of the more prominent elements of risk faced by Newfoundland Power.

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44 For example, in Order No. P.U. 32 (2007), the Board approved depreciation rates based upon a study which indicated that Company distribution assets had service lives between 36 and 50 years. (see *2006 Depreciation Study, Volume 3, Expert Evidence, Tab 3, Schedule 1, Newfoundland Power 2008 General Rate Application*.) This implies that the Company can expect to recover new investment in distribution assets over a 36 to 50 year time horizon.

45 See, for example, Order No. P.U. 19 (2003), page 33, where the Board indicated that the business risk profile of Newfoundland Power had not changed appreciably since 1998, and Order No. P.U. 43 (2009), page 13, where the Board found that Newfoundland Power continued to be an average risk Canadian utility.

Business Elements

Business Profile

Newfoundland Power is a relatively small electrical distribution utility which principally serves mature residential, commercial and institutional markets on the island of Newfoundland.[46] The Company currently serves approximately 250,000 customers. Large industrial customers on the island of Newfoundland are served by Hydro.

Over the past ten years, annual average energy sales growth for Newfoundland Power has been 1.8% and annual average growth in the number of customers served has been 1.3%.

Growth in service sector Gross Domestic Product for Newfoundland and Labrador ("GDP") has been approximately 2.6% per year over the past 10 years.[47]

For the five years ending in 2016, annual average sales growth for Newfoundland Power is forecast to be approximately 1.8%.[48] This reflects annual forecast service sector GDP growth of 1.5% over this period. For the next ten and twenty years, growth in provincial service sector GDP is forecast by the Conference Board of Canada to be 1.4% per year and 1.2% per year, respectively.

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[46] The relatively small size of Newfoundland Power has been recognized by the Board as an element of its risk profile insofar as it reduces the Company's financial flexibility and supports a stronger capital structure. See, for example, Order No. P.U. 16 (1998-99), page 37 and Order No. P.U. 19 (2003), page 45.

[47] Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2012*, May 2012. By contrast, the average annual growth in overall GDP for Newfoundland and Labrador for the 10 years ending in 2011 as reported by the Conference Board of Canada was 3.6%. This overall GDP growth is largely reflective of increased oil and mineral development in the province over the period. Newfoundland Power serves residential, commercial and institutional electricity markets. Growth in these markets has tended more to reflect growth in service sector GDP than overall GDP.

[48] Newfoundland Power does not forecast energy sales and the number of customers beyond 5 years.

Service Territory Demographics

Newfoundland and Labrador's population is in decline, increasingly urbanized and rapidly aging. Newfoundland and Labrador's population declined by 9.3% in the 20 years to 2011, and is expected to further decline by 5.6% through 2031.[49] The Conference Board of Canada is forecasting that Newfoundland and Labrador will be the only province with an absolute decline in population through 2031.[50]

Population losses in rural areas of the Province have been partly driven by increased migration to urban areas. This trend is expected to continue.[51]

Approximately 71% of the municipalities served by Newfoundland Power have a population of less than 1,000 people.[52] While 14% of Newfoundland Power's customers reside in these relatively small municipalities, approximately 40% of the Company's total distribution investment is dedicated to serving these customers.[53]

[49] The population of Newfoundland and Labrador was approximately 568,000 in 1991 and approximately 515,000 in 2011 representing a decline of 9.3% (515,000/568,000-1= -0.093), although in the decade from 2001 to 2011 the population increased marginally from approximately 513,000 to 515,000 (see Statistics Canada 2011 Census). Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2012*, May 2012, forecasts the population of the Province to be 486,000 in 2031, which represents a further decline of 5.6% (486,000/515,000-1= -0.056).

[50] Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2012*, May 2012.

[51] *Demographic Change: Issues & Implications*, Province of Newfoundland and Labrador, October 2006, page 7.

[52] Newfoundland Power currently serves 188 municipalities, of which 133 have a population of less than 1,000 people (133/188= 0.71, or 71%). In aggregate, these 133 municipalities have a population of 54,607 and contain (34,575/247163= 0.14, or 14%), of Newfoundland Power's customers.

[53] The total value of Newfoundland Power's distribution line assets at December 31, 2011 was approximately $452 million. The value of distribution line assets serving municipalities of less than 1,000 residents was $181 million, or 40% of total distribution line investment (181/452= 0.40, or 40%).

Over the 10 years to 2011, approximately 89% of these small municipalities experienced a decline in population.[54] In approximately 29% of these municipalities, the number of Newfoundland Power customers also declined during this period.[55] Similarly, in approximately 32% of these municipalities, Newfoundland Power's energy sales declined during this period.[56]

In seven municipalities served by Newfoundland Power, the population exceeds 10,000 people.[57] Approximately 43% of Newfoundland Power's customers reside in these seven municipalities.[58]

Over the 10 years to 2011, these larger municipalities experienced an aggregate increase in population of 11%.[59] The number of Newfoundland Power customers in these municipalities increased by approximately 20% during this period.[60] Similarly, Newfoundland Power's energy sales to customers in these municipalities increased by approximately 26% for the same period.[61]

Newfoundland and Labrador has one of the most rapidly aging populations in Canada.[62]

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[54] According to Statistics Canada 2011 Census, 118 of the 133 municipalities' populations declined over the 10 year period ending in 2011 (118/133= 0.89, or 89%).

[55] Over the 10 year period ending in 2011, 38 of the 133 municipalities saw a decline in the number of Newfoundland Power customers (38/133= 0.29, or 29%).

[56] Over the period 2001 to 2011, 43 of the 133 municipalities saw a decline in Newfoundland Power energy sales (43/133= 0.32, or 32%). The aggregate decline in energy sales was approximately 13 GWh.

[57] These are the cities of St. John's, Mount Pearl and Corner Brook, and the towns of Conception Bay South, Paradise, Grand Falls-Windsor and Gander.

[58] As at December 31, 2011, 107,093 of the 247,163 customers of Newfoundland Power resided in these 7 municipalities (107,093/247,163= 0.43, or 43%).

[59] The aggregate population in these municipalities was 196,610 in 2001 and 217,664 in 2011 according to Statistics Canada 2011 Census (217,664/196,610-1= 0.11, or 11%). This growth was not evenly spread amongst these 7 municipalities during this period. Over the 10 years to 2011, the cities of Mount Pearl and Corner Brook both experienced modest declines in population.

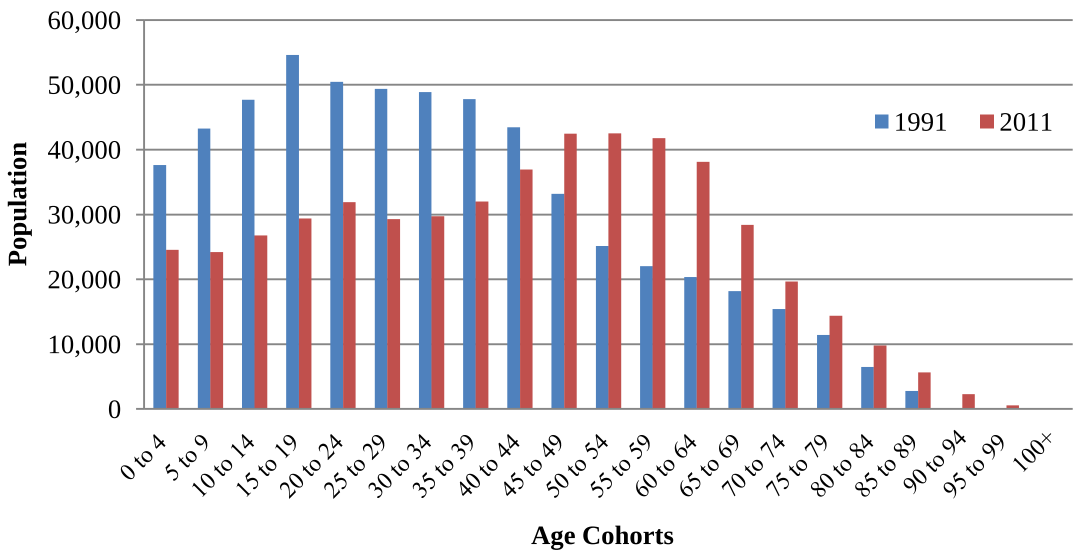
[60] In 2001, 89,619 Newfoundland Power customers resided in these municipalities, by 2011, the number of customers increased to 107,093 (107,093/89,619-1= 0.20, or 20%).

[61] In 2001, Newfoundland Power energy sales to customers resident in these municipalities totalled 2,362 GWh; by 2011, energy sales increased to 2,981 GWh (2,981/2,362-1= 0.26, or 26%).

[62] Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2012*, May 2012 has indicated that current trends will result in both a declining population and a faster aging of the population in Newfoundland and Labrador (see Executive Summary, page ii).

Graph 3-1 shows the population of Newfoundland and Labrador by age cohorts for 1991 and 2011.[63]

Graph 3-1
Newfoundland & Labrador
Population by Age Cohorts
1991 and 2011



The provincial population in 2011 is, on average, significantly older than it was in 1991. For example, the population of residents 19 years of age and under has significantly declined over the 20 year period, while the population of residents 50 years of age and over has significantly increased.[64]

In the 20 years to 2011, the population over 19 years of age within the Company's service territory grew by approximately 9.2%, while overall population declined by approximately

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63 See Statistics Canada, CANSIM table 051-0001, compiled by the Economics and Statistics Branch, Newfoundland & Labrador Statistics Agency.

64 In 1991, there were approximately 183,000 residents in the province 19 years of age and under compared to approximately 105,000 residents in 2011, a decrease of 43% (105,000/183,000-1= 0.43). In 1991, there were approximately 122,000 residents 50 years of age and over compared to approximately 203,000 in 2011, an increase of 66% (203,000/122,000-1= 0.66).

6.5%.[65] The increasing proportion of the population over the age of 19 resulted in increased household formation in the Company's service territory which, in turn, increased the number of customers served by the Company. In the 20 years to 2011, the overall number of customers served by Newfoundland Power grew by approximately 26%, or 1.3% per year.[66]

In the 20 years to 2011, the Company's overall energy sales grew by approximately 32%, or 1.6% per year.[67] The increasing number of customers was a primary reason for the increase in energy sales. The other principal contributor to energy sales growth was an increase in the market share of electric space heating over the period.[68]

Demographic trends already indicate a decline in the number of customers and energy sales in a material portion of Newfoundland Power's service territory. Forecast further population decline and accelerated aging can be expected to support continued decrease in portions of the Company's service territory. This is accompanied by concentrated growth in the larger urban centers.

These trends have implications for investment and long term cost recovery. The Company will be required to make increased investment to fulfill its obligation to serve growing populations in

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[65] In 1991, Newfoundland Power's service territory had an overall population of approximately 478,000, of which approximately 328,000 were 19 years of age or older. In 2011, overall population was approximately 447,000, of which 358,000 were 19 years of age or older. The decline in overall population in the Company's service territory was approximately 6.5% (447,000/478,000-1= -0.065). The increase in population over 19 years of age in the Company's service territory was approximately 9.2% (358,000/328,000-1= 0.092).

[66] In 1991, Newfoundland Power had approximately 196,000 customers and in 2011 approximately 247,000 customers, representing an increase of 26% (247,000/196,000-1= 0.260).

[67] In 1991, Newfoundland Power had approximately 4,196 GWh in energy sales and in 2011 approximately 5,553 GWh in energy sales, representing an increase of 32% (5,553/4,196 -1= 0.323).

[68] For example, in 2001, approximately 54% of Newfoundland Power customers used electricity as a primary heating source; by 2011, this had increased to approximately 63%.

urban centers.[69] In addition, ongoing investment will be required to fulfill the obligation to serve rural areas which have fewer customers and declining sales. The need to recover this increased investment from a declining customer base can be expected to exert increasing pressure on the Company's required investment return over the longer term.

Operating Conditions

Newfoundland Power is predominantly a distribution utility with a substantial heating load. Response to service interruptions, particularly in winter, is critical given the number of the Company's customers that rely on electricity for heating.

Approximately 80% of interruptions in electricity supply to customers result from electricity distribution system failures.[70] Weather conditions are the leading cause of electricity distribution system failure in Canada, including the island of Newfoundland.[71] The climate across the Company's service territory includes the most severe wind and ice conditions in populated regions of Canada.[72]

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69 For example, in 2010 and 2011, the Company installed 4 new power transformers to provide additional service capacity. This compares to a total of 6 new power transformers installed over the 19 year period from 1991 through 2009. The Company expects to install another 8 power transformers in the 5 year period from 2012 through 2016 at an average cost of over $3 million each.

70 Based upon the 5 year average system average interruption frequency index, or SAIFI, data for Newfoundland Power from 2007 to 2011.

71 Canadian Electricity Association, *Annual Service Continuity Report on Distribution System Performance in Electric Utilities*, 2010.

72 Data for historic weather is available from Environment Canada, National Climate Data and Information Archive website, http://climate.weatheroffice.gc.ca/winners/intro_e.html. For example, St. John's typically experiences 127 days each year where the average wind speed exceeds 40 km/hr, the most of any city in Canada. Similarly, both Gander and St. John's lead the country in the number of days each year where freezing rain is experienced.

These conditions are particularly hazardous for aerial transmission and distribution systems.[73]

Severe weather conditions increase volatility in the Company's operating and capital costs.[74]

Cost Flexibility

Table 3-11 shows revenue and costs for Newfoundland Power on a kWh basis for 1991, 2001 and 2011.[75]

Table 3-11
Revenue and Costs
¢ per kWh

	1991	**2001**	**2011**
Revenue	7.61	7.70	10.32
Energy Supply Costs	4.31	4.34	5.67
Fixed Costs[76]	1.57	1.71	3.01
Operating Costs	1.06	1.02	1.02
Operating Costs as % of Revenue	**14%**	**13%**	**10%**

Over the last 20 years, Newfoundland Power's electricity rates and revenues have increased primarily as a result of increased supply costs and fixed costs. The increase in fixed costs reflects increases in finance and depreciation costs associated with growing investment in the business. It also reflects the introduction of a demand charge into the wholesale rate structure in 2005 and increased recovery of employee future benefit costs since 2008. Energy supply costs

[73] High winds and freezing rain contribute to unscheduled outages on the Company's overhead distribution and transmission infrastructure. By way of example, major weather events in 2010 resulted in unplanned expenditures of approximately $10 million. In March 2010, an ice storm caused $4.2 million in damage to the Company's transmission and distribution systems. In September 2010, the Company incurred approximately $5.5 million in additional expenditures resulting from Hurricane Igor.

[74] For some utilities, such as those in Alberta, specific regulatory accounts exist to provide for the deferred recovery of uninsured damage over $100,000 that results from severe weather events.

[75] Revenue and cost on a kWh basis are defined as the annual revenue and cost divided by the kWh sales in the same year.

[76] Fixed costs include demand supply costs, depreciation, employee future benefit costs, finance costs and income taxes.

and fixed costs, which increased materially in the last 10 years, currently comprise approximately 84% of revenues on a kWh basis. These costs are substantially beyond management control in any year.

Newfoundland Power's nominal operating costs on a kWh basis have been stable over the 20 years to 2011.[77] However, operating costs as a proportion of revenue have declined since 1991. The Company's operating costs, over which a *degree* of management control can be expected, currently comprise approximately 10% of revenue.[78]

While reducing operating costs on a real basis is reflective of sound management, the decreasing *proportion* of operating costs reduces the Company's flexibility to respond to extraordinary operating events such as those related to weather.[79]

Power Supply

Newfoundland Power is dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers.[80]

[77] This *nominal* stability masks considerable improvement in the Company's operating productivity over the 20 year period. Inflation in the 20 years ending in 2011 was 43.8%.

[78] While operating costs are subject to a *degree* of management control, the extent of that control varies by the nature of the cost. For example, the reduction of labour costs associated with full time employees may not be controllable in the short term due to severance obligations. On the other hand, 3rd party maintenance arrangements may be controllable in the short term, depending on agreements.

[79] See Footnote 73.

[80] Currently, Newfoundland Power purchases approximately 93% of its power supply requirements from Hydro. Newfoundland Power has no practical alternative to Hydro for the additional power supply required to meet increasing customer load.

Power purchases from Hydro are Newfoundland Power's largest cost, accounting for approximately 66% of revenue from rates in 2011.[81]

Newfoundland Power's single supply dependence is relatively rare for investor owned electric utilities in Canada.[82] Currently, the Company effectively recovers its power supply costs through a combination of customer rates and regulatory mechanisms.[83]

Newfoundland Power's single supply dependence limits management's ability to influence the Company's largest cost.[84] While this circumstance does not materially affect current recovery of the Company's cost of service, it could possibly do so in the future. Further, the impact of power supply costs on customer rates could serve to influence consumer behaviour and restrict sales growth or promote sales decline. Finally, abrupt increases in power supply costs could have the effect of delaying recovery of Newfoundland Power's other costs.[85]

Regulatory Elements

Regulatory Framework

Newfoundland Power is regulated on a cost of service basis consistent with other investor owned utilities across Canada. Section 80 of the *Public Utilities Acts* (the "Act") provides that in

[81] Newfoundland Power's 2011 purchased power costs were approximately $369 million; 2011 revenue from rates was approximately $559 million (369/559= 0.66, or 66%).

[82] In Ontario and Alberta, energy supply for distribution to consumers is coordinated at a wholesale level by independent market operators which effectively ensure least cost supply on a real-time basis through competitive bidding. In Nova Scotia, Prince Edward Island and British Columbia, electric utilities are practically able to seek competitive sources of energy supply in regional wholesale markets. Saskatchewan, Manitoba and New Brunswick do not have investor owned electric utilities.

[83] See pages 3-26 to 3-28 for a description of the regulatory mechanisms that permit Newfoundland Power to recover its power supply costs.

[84] Newfoundland Power management does have some limited ability to influence power supply costs included in customer electricity rates through the regulatory process.

[85] This point has been made by the Dominion Bond Rating Service in the context of credit risk assessment (see *Volume 2, Exhibits & Supporting Materials, Exhibit 4* for *DBRS Rating Report*, September 10, 2012, page 2).

addition to recovery of its prudently incurred costs, a public utility is also entitled to earn annually a just and reasonable return on its rate base.

Section 3 (a) (iii) of the *Electrical Power Control Act, 1994* (the "EPCA") provides that the rates approved by the Board should provide sufficient revenue to a utility "…to enable it to earn a just and reasonable return as construed under the *Public Utilities Act* so that it is able to achieve and maintain a sound credit rating in the financial markets of the world…".

Section 80 of the Act, together with Section 3 (a) (iii) of the EPCA are the cornerstones of the regulatory framework governing the recovery of costs and establishment of returns for public utilities in Newfoundland & Labrador.

Cost Recovery

The Board has approved regulatory mechanisms to ensure reasonable recovery of (i) supply costs, including those due to variations in weather; and (ii) employee future benefit costs.

Newfoundland Power's RSA is the primary means by which changes in supply costs from Hydro are recovered. This account principally recovers variations in the cost of fuel burned at Hydro's Holyrood Thermal Generating Station.[86]

[86] The RSA was originally approved by Order No. P.U. 34 (1985) to enable Newfoundland Power to flow through changes in Hydro's fuel costs.

The RSA also recovers, or credits, as appropriate, variations in Newfoundland Power's supply costs due to changes from test year energy and demand costs.[87] The RSA effectively limits Newfoundland Power's risk of recovery of supply costs to approximately ± $550,000, which represents approximately 25% of the range of return on rate base typically approved by the Board. Supply cost recovery or flow through mechanisms are common Canadian regulatory practice for distribution utilities.[88]

Newfoundland Power's Weather Normalization Reserve adjusts revenue and power supply costs to account for variations in weather.[89] Such adjustments ensure that Newfoundland Power experiences neither an earnings windfall nor an earnings shortfall as a result of weather conditions. Normalization of revenue and supply costs for weather is common for regulated utilities that supply a substantial heating load.[90]

Newfoundland Power has variation accounts to ensure recovery of only those employee future benefit costs which are actually incurred by the Company.[91] Recovery accounts for utility

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[87] In Order No. P.U. 32 (2007), the Board originally approved a change in the RSA to permit Newfoundland Power to recover the difference between the marginal energy supply cost from Hydro and the average energy supply cost from Hydro. Given supply cost dynamics on the island grid, without such a recovery, annual GRAs would be necessary for Newfoundland Power. In Order No. P.U. 32 (2007), the Board also approved the potential recovery or credit of demand costs through the RSA where demand costs vary by more than 1% from test year demand costs. Recovery or credit is subject to Board approval which includes consideration of Newfoundland Power's demand management activities. Demand management incentives achieved by Newfoundland Power have resulted in credits to customers of approximately $6 million since 2005.

[88] Currently, cost recovery or flow through mechanisms have been approved for supply cost or margin variations for utilities in all provinces except Manitoba and Saskatchewan where the utilities are not investor-owned.

[89] Normalization associated with hydraulic production originated in Order No. P.U. 32 (1968). Normalization associated with sales and purchase variations related to space heating originated in Order No. P.U. 1 (1974).

[90] These are typically natural gas distribution utilities.

[91] The variation accounts ensure recovery of annual defined benefit pension costs and other post-employment benefit costs. Each account operates to true up estimated costs to actual costs. The defined benefit pension variation account was approved in Order No. P.U. 43 (2009). The other post-employment benefit variation account was approved in Order No. P.U. 31 (2010).

employee future benefit costs have become more common as a result of a combination of changes in accounting practice and financial market conditions.[92]

Return Limits

Historically, the Board has approved a range of return on rate base for Newfoundland Power. This has partially been justified on the basis that setting a reasonable rate of return is not an exact science, no matter what methodology is adopted by the regulator to establish the return. It has also been justified partially by the Board's desire to limit the return that Newfoundland Power may actually earn in any given year.[93] Use of a range has also been justified for its incentive effect.[94]

Newfoundland Power has an Excess Earnings Account which captures all earnings in excess of the upper limit of the range of return on rate base approved by the Board.[95] The typical range approved by the Board for Newfoundland Power is ± 0.18% return on rate base which broadly equates to ± 0.375% return on equity on a *pro forma* basis. The Excess Earnings Account effectively limits the return on equity that Newfoundland Power is capable of earning to approximately $1.5 million more than the allowed return on equity used for ratemaking purposes

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92 Changes in accounting practice have included the adoption of the annual marking to market of future benefit obligations and fund assets. This has increased the annual volatility of employee future benefit costs. Currently, recovery mechanisms have also been approved for employee future benefit costs for utilities in Alberta and British Columbia.

93 See Paragraphs 25 *et. seq.* of the June 15, 1998 Court of Appeal decision in the Stated Case.

94 See, for example, Order No. P.U. 19 (2003), page 76, where the Board indicated its view that "…the range of return on rate base can act as an incentive device to encourage NP to seek efficiencies between rate hearings, which can then be passed on to customers."

95 See, for example, Order Nos. P.U. 32 (2010) and P.U. 46 (2009).

in a test year. The Excess Earnings Account does not provide for the recovery of shortfalls in earned returns below the range approved by the Board.[96]

The Excess Earnings Account creates an element of asymmetry in Newfoundland Power's earnings risk. Sharing of earnings variances between utilities and customers has been a feature of certain performance based ratemaking regimes in Canada.[97] However, a cap such as that created by the Company's Excess Earnings Account is relatively rare among Canadian investor owned utilities.

Financial Elements

Capital Structure

Table 3-12 shows the targeted capital structure of Newfoundland Power.

Table 3-12
Targeted Capital Structure

Debt	54%
Preferred Equity	1%
Common Equity	45%

[96] See Paragraph 70 of the June 15, 1998 Court of Appeal decision in the Stated Case where the Court found, "While the utility, if it earned as much as the maximum would be entitled to keep that amount of earnings, it is not, for reasons already given, guaranteed that level of return if it is not in fact successful in earning them. *The Board is under no obligation to adjust future rates or to take other steps to make up any such shortfall*." (Italics added).

[97] In British Columbia, sharing of positive and negative variances between approved and actual regulated earnings between customers and utilities has been part of performance based regulatory schemes for gas and electric utilities.

The Company's target of 45% common equity in its capital structure is consistent with Board orders since 1990.[98] Newfoundland Power's capital structure is a relative strength that mitigates risks associated with the Company's small size and low long term forecast growth estimates.[99]

Credit Ratings

The most recent credit rating reports from DBRS Limited ("DBRS") and Moody's Investors Services ("Moody's") are found in *Volume 2, Exhibits & Supporting Materials*, *Exhibit 4*.

Table 3-13 shows DBRS and Moody's current credit ratings for Newfoundland Power.

Table 3-13
Credit Ratings

Rating Agency	Issuer Rating	Bond Rating
DBRS	-[100]	A, Stable
Moody's	Baa1	A2, Stable

Both DBRS and Moody's assess the Company's creditworthiness on a stand-alone basis.

Newfoundland Power's first mortgage bonds are its primary source of long term debt financing. These bonds have held an investment grade rating from two credit rating agencies throughout the past two decades.

98 See Order Nos. P.U. 1 (1990), P.U. 6 (1991), P.U. 7 (1996-97), P.U. 16 (1998-99), P.U. 19 (2003), P.U. 32 (2007), and P.U. 43 (2009).

99 See Footnote 46.

100 DBRS does not rate the issuer of securities; it only rates the securities issued.

Newfoundland Power's current credit ratings are investment grade and are consistent with both (i) least cost service delivery to customers over the long term and (ii) maintaining a sound credit rating in the financial markets of the world as required under the Act.

3.3.2 Automatic Adjustment Formula

Regulatory Objectives

The Board first ordered adoption of the Formula in 1998. At that time, the principal benefits were expected to be reduced costs resulting from less frequent reviews of cost of capital and reduced regulatory uncertainty.[101]

Following adoption of the Formula in 1998, Newfoundland Power's cost of capital was re-examined in the Company's 2003 and 2008 GRAs. For the most part, during the decade ending in 2007 (the year the Company's 2008 GRA was determined), the Formula appeared to broadly achieve the regulatory objectives of less frequent reviews of cost of capital and reduced regulatory uncertainty.[102]

Since 2008, the Formula has failed to produce either fewer reviews of Newfoundland Power's cost of capital or reduced regulatory uncertainty. Instead, the Formula has yielded estimates of Newfoundland Power's cost of equity which have triggered successive re-examinations of the

[101] See, for example, Order No. P.U. 16 (1998-99), Page 103 and Order No. P.U. 43 (2009), Pages 28-29.
[102] Modifications to the Formula occurred in this period. For example, in Order No. P.U. 19 (2003), the Board ordered changes in the series of Long Canada Bond Yields used to estimate the risk-free rate (see page 66-67 of the Order).

Company's cost of capital and the operation of the Formula.[103]

Brief History of the Formula

Cost of capital formulas to determine return on equity for ratemaking purposes originated with the BCUC decision to adopt a formula in 1994.[104] Following this, the NEB and the Manitoba PUB each adopted formulas to estimate the cost of equity for 1995.[105] The AUC, the OEB and the Régie also adopted formulas for this purpose over the period 1997 to 2004. In Order No. P.U. 16 (1998-99) the Board ordered the implementation of the Formula.[106]

In 2009, a number of Canadian utility regulators, including the Board, NEB, OEB, BCUC, the Régie and AUC, reconsidered formula based approaches to annually update cost of equity based on forecast changes in long Canada bond yields.

The NEB, BCUC and AUC chose to discontinue or suspend the operation of their formulas.[107]

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[103] Applications to the Board related to the Company's ratemaking returns on equity have increased markedly since 2008. In the applications resulting in Order Nos. P.U. 32 (2007), P.U. 43 (2009) and P.U. 17 (2012) and in this Application, the sufficiency of the ratemaking returns on equity of Newfoundland Power were, or are, at issue. In the applications resulting in Order Nos. P.U. 35 (2008), P.U. 12 (2010), P.U. 32 (2010) and P.U. 25 (2011), the mechanics, operation or suspension of the Formula were at issue. Given this level of regulatory attention, it is difficult to maintain that, since 2008, the Formula has contributed to either reduced regulatory costs or reduced regulatory uncertainty.

[104] The BCUC adopted a formula to determine return on equity in Decision No. G-35-94.

[105] The NEB established a formula for return on equity for 6 nationally regulated gas pipelines in Decision RH-2-94. The Manitoba PUB determined in Order 103/05 that a formula would be used as an upper bound reasonableness check on return for Centra Gas.

[106] The details of implementation, including the accounting methodology used to annually calculate a return on rate base for Newfoundland Power, were addressed by the Board in Order No. P.U. 36 (1998-99).

[107] In 2009, both the NEB and BCUC eliminated their formulas. The NEB continues to publish the results of the discontinued formula for the purposes of parties that are still bound by settlements based on the previous adjustment formula. In 2009, the AUC suspended the use of its formula for 2010 pending a further review. The AUC did not reinstate its formula in its 2011 decision (see Decision 2011-474, December 8, 2011). These changes were primarily due to the perceived inability of formulas based upon long term Government of Canada bond yields to predict a fair forecast cost of equity in then-current market conditions.

The OEB, the Régie and the Board continued the use of formulas.[108]

In Order No. P.U. 43 (2009), the Board determined that Newfoundland Power's rate of return on rate base for 2011 and 2012 would be set using the Formula.

The Formula, as effectively approved by the Board in 2009, was:

Forecast cost of equity = 9.00 + (0.80 (RFR – 4.50))

where:

(i) 9.00 is the cost of equity approved for ratemaking purposes in 2010;
(ii) 0.80 is the adjustment coefficient for the change in the forecast risk-free rate;
(iii) RFR is the risk-free rate; and,
(iv) 4.50 is the risk-free rate approved by the Board for the 2010 test year.

The Board continued use of the Formula without materially increasing the benchmark return on equity.

The allowed return on equity of 9% for 2010 established by Order No. P.U. 43 (2009) was only 0.13% higher than the 8.87% indicated by the Formula using a long Canada bond yield of 4.5%.[109] Other regulators that retained the use of formulas in 2009 made materially larger increases to their risk premium component.[110] In its 2009 Order, the Board indicated it believed

108 In 2009, the OEB modified its formula to include a second independent variable based on observed credit spreads. In addition, it reduced the coefficient on long Canada bond yields from 75% to 50% and rebased the benchmark return on equity to 9.75%. Based upon the previous OEB formula, the benchmark return on equity would have been 8.4%. In 2009, the Régie continued use of a formula based approach to establish the cost of equity for Gaz Metro for 2011, but reset the 2010 base return on equity to a higher level to take account of financial market conditions. Gaz Metro's return on equity was effectively set at a level 0.5% higher than it would have been under the previous formula.

109 This 9.0% allowed return on equity was based on a 4.5% risk-free rate and a 4.5% equity risk premium (see Order No. P.U. 43 (2009), page 25). If a 4.5% risk-free rate had been used in the Formula for 2010, the risk premium would have been 4.37%, for an allowed return on equity of 8.87%.

110 The OEB's 9.75% allowed return on equity was based on a 4.25% risk-free rate and an equity risk premium of 5.5%. See Decision EB-2009-0084, December 11, 2009, page 37. The Regie's 9.20% allowed return on equity was based upon a risk-free rate of 4.30% and an equity risk premium of 4.90%. See Decision D-2009-156, December 7, 2009, page 28.

continued use of a formula to adjust Newfoundland Power's return on rate base was appropriate, as financial market conditions appeared to be settling.[111]

Modifications to the calculation of the risk-free rate were approved by the Board in Order No. P.U. 12 (2010).[112]

For 2012, the Formula indicated an estimated cost of equity for Newfoundland Power of 7.85%.[113] Based upon the August 2012 *Consensus Forecasts*, the Formula would indicate an estimated 2013 cost of equity for Newfoundland Power of 7.53%.[114] These ratemaking returns on equity are materially lower than the ratemaking return on equity of 9% allowed by the Board for 2010.

Financial market conditions became increasingly unstable in the last half of 2011. These conditions included unusually low and volatile Government of Canada bond yields. Forecast yields of Government of Canada 30 year benchmark bonds ("Long Canada Bond Yields") are currently used in the Formula as a risk-free rate. Because of this, the *decline* in the forecast cost of equity indicated by the Formula simply reflects the decline in Long Canada Bond Yields.

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[111] See Order No. P.U. 43 (2009) at page 29, lines 18-19 and page 29, lines 32-36.

[112] As a result of the modifications approved in Order No. P.U. 12 (2010), the risk-free rate is determined by adding (i) the average of the 3 month and 12 month forecast of 10 year Government of Canada Bonds as published by *Consensus Forecasts* in the preceding November and (ii) the average observed spread between 10 year and 30 year Government of Canada Bonds for all trading days in the preceding October.

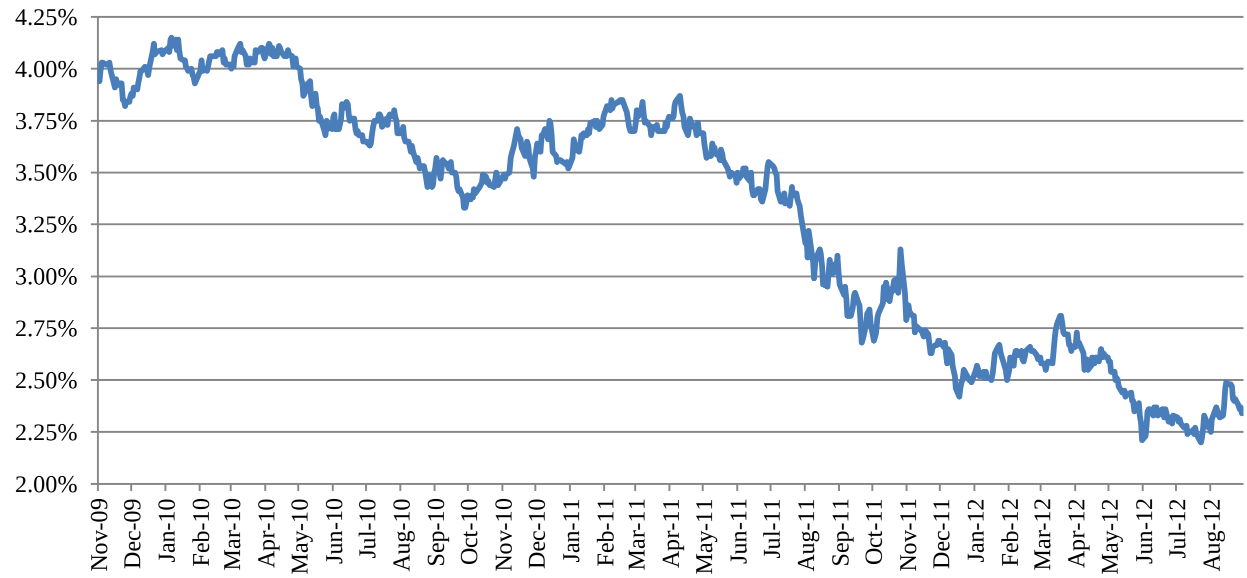
[113] For 2012, the forecast cost of equity as determined by the Formula is calculated as follows: 9.00 + (0.80 (3.06-4.50)) = 7.85%.

[114] The *pro forma* 2013 forecast cost of equity based upon the August *Consensus Forecasts* is calculated as follows: 9.00 + (0.80 (2.66-4.50)) = 7.53%. The November *Consensus Forecasts* is used to establish the risk-free rate in the operation of the Formula.

Bond Yields and Forecasts

Graph 3-2 shows the daily Long Canada Bond Yields from November 2, 2009 to August 31, 2012.

Graph 3-2
Government of Canada Benchmark
30 Year Daily Bond Yields



Since November 2009, Long Canada Bond Yields have declined appreciably.[115] At August 31, 2012, the benchmark bond yield was 2.34%. Current Long Canada Bond Yields are well below those used to establish Newfoundland Power's 2010 ratemaking return on equity.

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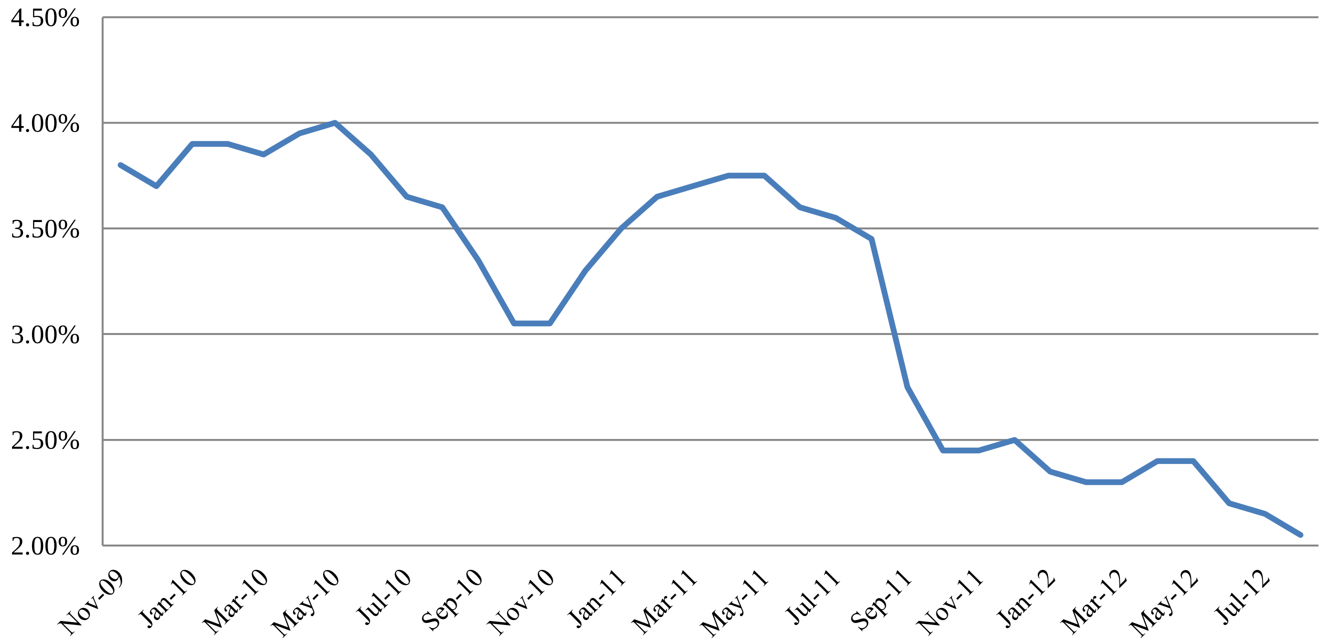
[115] In November 2009, Long Canada Bond Yields averaged 3.94%. In August 2012, Long Canada Bond Yields averaged 2.38%.

Graph 3-3 shows the average of the 3 month and 12 month forecasts of 10 year Government of Canada bond yields as published by *Consensus Forecasts* monthly from November 2009 through August 2012.

Graph 3-3
Consensus Forecasts - Forecast of 10 Year Bond Yields



Since November 2009, forecast 10 year Government of Canada bond yields have declined appreciably.[116] At August 2012, the monthly average of the 3 month and 12 month forecasts as published by *Consensus Forecasts* was 2.05%. Low Long Canada Bond Yields and low 10 year bond yield forecasts are influenced by federal monetary policy encouraging low interest rates in current economic conditions.[117]

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[116] In November 2009, the forecast 10 year Government of Canada bond yields averaged 3.8%. In August 2012, the forecast 10 year Government of Canada bond yields averaged 2.05%.

[117] The Bank of Canada policy encouraging low interest rates was confirmed in its *Monetary Policy Summary Report*, January 2012. Canadian monetary policy is not, however, the only contributor to low long term bond yields. For a discussion of other factors, see Ms. McShane's Evidence, *Volume 3, Expert Evidence & Studies, Tab 1*, page 44, lines 1112 to 1119.

The broad economic outlook continues to appear unsettled and subject to possible further political or governmental intervention. The Department of Finance Canada communiqué of February 26th, 2012 indicated that:

> "The international economic environment has continued to be characterized by an uneven performance, with weak growth in advanced economies and a stronger, albeit slowing, expansion in emerging markets. Structural problems, insufficient global rebalancing, a persistent development gap and high levels of public and private indebtedness and uncertainty continue weighing on medium-term global growth prospects. *While volatility in international financial markets has declined, it generally remains high and we are committed to further reduce downside risks*."[118]

By June 2012, the Bank of Canada was indicating that "The global recovery remains modest, fragile and uneven." and that "While the financial system in Canada is in good condition, …. the overall level of risks to the system remains high."[119]

Concluding

Section 80 of the Act entitles Newfoundland Power to a reasonable opportunity to earn a just and reasonable return *each year*.

In Order No. P.U. 43 (2009), the Board ordered continued use of the Formula as it believed financial market conditions appeared to be settling. The 8.38% estimated cost of equity indicated by the Formula for 2011 was the result of declining forecast Long Canada Bond

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118 *Communiqué of Finance Ministers and Central Bank Governors of the G-20*, Mexico City, February 26, 2012; Department of Finance Canada, 2012-022. (Italics added).

119 Bank of Canada, *Financial System Review* June 2012, pages 5 and 33.

Yields. It was also the lowest ratemaking return on equity awarded for a Canadian investor owned electric utility in 2011.[120]

The estimated cost of equity of 7.85% indicated by the Formula for 2012 did not constitute a fair return for Newfoundland Power. The August 2012 *Consensus Forecasts* indication of an estimated cost of equity of 7.53% for 2013 does not constitute a fair return for Newfoundland Power. Both are well below current ratemaking returns on equity for Canadian investor owned electric utilities.[121]

The current increased uncertainty associated with forecasting Long Canada Bond Yields largely reflects monetary policy. The Formula should be discontinued as it does not accurately estimate the appropriate return on equity under current financial market conditions.

3.3.3 Impact of Proposed Return

Table 3-14 shows Newfoundland Power's credit metrics from 2010 to 2014 under existing customer rates.[122]

Table 3-14
Credit Metrics
2010 to 2014E

	2010	2011	2012F	2013E	2014E
Pre-tax Interest Coverage (times)	2.4	2.4	2.3	2.2	2.1
Cash Flow Interest Coverage (times)	3.4	3.2	3.2	3.2	3.0
Cash Flow Debt Coverage (%)	17.6	16.4	15.7	15.5	13.7

[120] For 2011, ratemaking returns on equity for Canadian investor owned electric utilities, other than Newfoundland Power, ranged from a low of 9% in Alberta to a high of 9.9% for British Columbia-based FortisBC.

[121] For 2012, ratemaking returns on equity for Canadian investor owned electric utilities, other than Newfoundland Power, range from a low of 8.75% in Alberta to a high of 9.9% in British Columbia. BCUC Order No. G-20-12, establishes a proceeding to determine the appropriate cost of capital for a benchmark low risk utility effective January 1, 2013.

[122] See *Volume 2, Exhibits & Supporting Materials, Exhibit 3*.

Existing customer rates reflect a return on equity of 8.38%.[123] Under existing customer rates, each of Newfoundland Power's forecast credit metrics deteriorates in 2013 to 2014. This is not consistent with the maintenance of the continued financial integrity of the Company.

In this Application, Ms. Kathleen McShane and Dr. James Vander Weide have provided expert opinion on a fair return on equity for Newfoundland Power for 2013 and 2014.[124] In Ms. McShane's opinion, a fair return on equity for Newfoundland Power for 2013 and 2014 is 10.5%. In Dr. Vander Weide's opinion, a fair return on equity for Newfoundland Power for 2013 and 2014 is 10.4%.

Exhibit 5 in *Volume 2, Exhibits & Supporting Materials*, shows *pro forma* 2014 Newfoundland Power credit metrics across a range of capital structures and common equity ratios.

Exhibit 6 in *Volume 2, Exhibits & Supporting Materials*, shows Newfoundland Power's actual financial performance for 2010 and 2011 and forecast financial performance for 2012, 2013 and 2014 assuming the proposed customer rates in this Application are approved effective March 1, 2013.

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[123] In Order No. P.U. 17 (2012), the Board approved a 2012 return on equity of 8.80% for Newfoundland Power, however, customer rates were not adjusted to reflect this return on equity. Instead, the Board approved a 2012 cost recovery deferral of approximately $2.5 million to reflect the forecast difference for 2012 between a ratemaking return on equity of 8.38% and 8.80% (see *Section 3.5.1 2011 to 2012 Deferrals*). Accordingly, existing customer rates reflect the 2011 ratemaking return on equity of 8.38% that was determined by the Formula and approved by the Board in Order No. P.U. 32 (2010).

[124] Ms. McShane's and Dr. Vander Weide's expert evidence is found in *Volume 3, Expert Evidence & Studies, Tabs 1 and 2* respectively.

Table 3-15 shows Newfoundland Power's credit metrics under existing customer rates and under the customer rates proposed in this Application.[125]

Table 3-15
Credit Metrics
Existing and Proposed
2013 and 2014

	2013E	2013P	2014E	2014P
Pre-tax Interest Coverage (times)	2.2	2.6	2.1	2.7
Cash Flow Interest Coverage (times)	3.2	3.6	3.0	3.4
Cash Flow Debt Coverage (%)	15.5	18.3	13.7	16.4

Under the customer rates proposed in this Application, Newfoundland Power's forecast credit metrics are improved compared to the forecast credit metrics under existing rates. The forecast credit metrics under the customer rates proposed in this Application are consistent with the maintenance of the continued financial integrity of the Company.

3.4 REGULATORY ACCOUNTING MATTERS

In this Application, Newfoundland Power is proposing changes to certain regulatory accounting matters.

With this Application, the Company has filed a 2010 Depreciation Study, updated to reflect the 2011 sale of joint use poles to Bell Aliant (the "2010 Depreciation Study"). Based on the 2010 Depreciation Study, the Company proposes to implement new depreciation rates and amortize an accumulated reserve variance of $2.6 million beginning in 2013.

[125] The rates proposed in this Application have been calculated using a return on common equity for the Company of 10.4% in each of 2013 and 2014.

Pursuant to Order No P.U. 27 (2011), Newfoundland Power adopted U.S. GAAP for regulatory purposes effective January 1, 2012 and addressed certain transitional matters. In this Application, Newfoundland Power is proposing to commence recognizing pension expense for regulatory purposes in accordance with U.S. GAAP on January 1, 2013.

In this Application, Newfoundland Power is proposing to commence deferring annual customer energy conservation program costs and recovering them over a 7 year period. This will better reflect the cumulative nature of benefits associated with this program.

Newfoundland Power is also proposing in this Application that, commencing in 2013, year end balances in the Weather Normalization Reserve be credited to, or recovered from, customers annually through the RSA.

This section of the evidence addresses matters related to (i) depreciation expense for 2013 and 2014; (ii) the proposed change to accounting for pension expense in accordance with U.S. GAAP on January 1 2013; (iii) the proposed change in accounting for customer energy conservation program costs; and (iv) the proposed change in recovery of year end balances in the Weather Normalization Reserve.

The accounting proposals included in this Application will reduce the Company's revenue requirements by approximately $2.9 million in 2013 and approximately $4.2 million in 2014.

3.4.1 2010 Depreciation Study

General

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.[126]

The 2010 Depreciation Study prepared by Gannett Fleming, was based upon the plant in service as at December 31, 2010.[127] The 2010 Depreciation Study incorporates the sale of 40% of joint use poles to Bell Aliant in 2011.

A copy of the *2010 Depreciation Study* is filed in *Volume 3, Expert Evidence & Studies, Tab 3.*

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[126] Since 1996, Newfoundland Power has retained Gannett Fleming Valuation and Rate Consultants, Inc. ("Gannett Fleming") to perform comprehensive depreciation studies of Company plant in service at 5 year intervals. See Order Nos. P.U. 7 (1996-97), P.U. 19 (2003) and P.U. 32 (2007).

[127] In Order No. P.U. 32 (2007), the Board ordered Newfoundland Power to prepare its next depreciation study related to plant in service as of December 31, 2010. In Order No. P.U. 43 (2009), the Board approved Newfoundland Power's proposal that its next depreciation study relate to plant in service as of December 31, 2009 to accommodate the adoption of International Financial Reporting Standards ("IFRS") effective January 1, 2011. Newfoundland Power never adopted IFRS. In Order No. P.U. 27 (2011), the Board approved Newfoundland Power's adoption of United States generally accepted accounting principles ("U.S. GAAP") for regulatory purposes effective January 1, 2012. As Newfoundland Power's adoption of U.S. GAAP effective January 1, 2012, did not require a depreciation study relating to plant in service as at December 31, 2009, the Company had its next depreciation study relate to plant in service as at December 31, 2010, as initially ordered in Order No. P.U. 32 (2007). Newfoundland Power's last depreciation study related to plant in service as at December 31, 2005.

Depreciation Rates

Table 3-16 shows both existing annual depreciation rates and those indicated in the 2010 Depreciation Study by asset class.

Table 3-16
Annual Depreciation Rates
(%)

Asset Class	**Existing**	**2010 Study**
Hydro Production	2.17	2.41
Other Production	4.73	5.09
Substation	2.63	2.67
Transmission	3.28	3.23
Distribution	3.14	3.18
General		
Computer – Hardware	20.00	20.00
Computer – Software	10.00	10.00
Transportation	10.28	9.73
Other	2.94	2.97
Communications	6.18	5.37
Composite Rate	**3.47**	**3.42**

The 2010 Depreciation Study indicates a composite 2010 depreciation rate of 3.42%.

Accumulated Reserve Variance

The 2010 Depreciation Study provides a comparison between the accumulated depreciation recorded by the Company with respect to plant in service as of December 31, 2010 and a calculated, or theoretical, reserve based on the new depreciation rates recommended in the 2010 Depreciation Study.

The difference is referred to as the accumulated reserve variance. In the 2010 Depreciation Study, Gannett Fleming has calculated the accumulated reserve variance as at December 31, 2010 to be $2.6 million.[128]

2013 and 2014 Depreciation Expense

Newfoundland Power proposes to implement the depreciation rates resulting from the 2010 Depreciation Study effective January 1, 2013. Newfoundland Power also proposes to amortize the accumulated reserve variance of $2.6 million over the composite remaining life of the assets.[129]

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[128] The accumulated reserve variance of $2.6 million represents, in effect, an historical under-recovery of depreciation. Amortization of this under-recovery will serve to *increase* Newfoundland Power's revenue requirements. Gannett Fleming recommends that where the accumulated reserve variance as at December 31, 2010 exceeds 5% 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 2010 Depreciation Study.

[129] In the past, the Board has approved amortization of accumulated reserve variances over relatively short fixed terms of 3 to 5 years. 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. In Order No. P.U. 32 (2007), the Board approved a four year amortization period. In each of these cases, the amortization of the accumulated reserve variance served to *decrease* Newfoundland Power's revenue requirements.

Table 3-17 shows the changes in depreciation expense for 2013 and 2014 which result from the proposed (i) use of the depreciation rates contained in the 2010 Depreciation Study and (ii) amortization of the accumulated reserve variance over the remaining life of the assets.[130]

Table 3-17
2013 and 2014 Proposed Depreciation Expense
($000s)

	2013	**2014**
Depreciation Expense - Current Rates	45,942	47,561
Proposed Depreciation Rates	616	641
Proposed Reserve Variance Amortization	89	89
Proposed Depreciation Expense	46,647	48,291
Difference	**705**	**730**

The proposed changes to depreciation expense will increase the amount of depreciation expense required to be recovered in customer rates by approximately $0.7 million per year.

3.4.2 Employee Future Benefits Costs

In the 4th quarter of 2011, Newfoundland Power decided to adopt U.S. GAAP for financial reporting purposes effective January 1, 2012. In Order No P.U. 27 (2011), the Board approved Newfoundland Power's adoption of U.S. GAAP for regulatory purposes and addressed certain transitional matters. These transitional matters were reflected in timing differences associated with the recognition of employee future benefit costs, particularly defined benefit pension

[130] The use of the depreciation rates contained in the *2010 Depreciation Study* resulted in a 2010 composite depreciation rate of 3.42% which is lower than the currently approved composite depreciation rate of 3.47%. Increases in forecast 2013 and 2014 depreciation which result from implementation of the depreciation rates contained in the *2010 Depreciation Study* are a result of the changing composition of the Company's overall assets.

costs.[131] These timing differences were reflected in regulatory assets and liabilities.[132] One component of the regulatory assets created upon Newfoundland Power's adoption of U.S. GAAP for regulatory purposes reflected differences in annual defined benefit pension expense calculated under U.S. GAAP and Canadian GAAP in 2011.[133]

Table 3-18 shows defined benefit pension expense under Canadian GAAP in 2011[134] and U.S. GAAP.

Table 3-18
Defined Benefit Pension Expense
Canadian GAAP and U.S. GAAP
2011 to 2015F
($000s)

	2011	**2012F**	**2013F**	**2014F**	**2015F**
U.S. GAAP	10,708	11,948	9,801	9,169	7,328
Canadian GAAP	10,271	11,367	11,150	10,566	8,602
Difference	**437**	**581**	**(1,349)**	**(1,397)**	**(1,274)**

131 The adoption of U.S. GAAP for regulatory purposes by Newfoundland Power affected the *timing* of recognition of costs not the *amount* of costs to be recovered by the Company.

132 These timing differences were reflected in opening balances for regulatory assets and liabilities as at January 1, 2012, totalling approximately $131.2 million. Of this amount, approximately $110.1 million was related to timing differences associated with Newfoundland Power's defined benefit pension plans.

133 The amount of this timing difference is approximately $11.8 million which results from a difference in the period over which the cost of defined pension benefits may be attributed under U.S. GAAP and Canadian GAAP in 2011.

134 Further references to Canadian GAAP in this section will refer to Canadian GAAP as it existed in 2011 and applied to Newfoundland Power. Commencing in 2012, Canadian GAAP effectively became International Financial Reporting Standards.

Commencing in 2013, annual defined benefit pension expense calculated under U.S. GAAP will be lower than under Canadian GAAP.[135] Currently, these annual differences in defined benefit pension expense are recognized as part of the Company's regulatory assets and liabilities and are not directly included in the calculation of Newfoundland Power's annual revenue requirements.[136] The sum of these differences is forecast to constitute a regulatory asset of approximately $12.4 million as at December 31, 2012.[137]

In this Application, Newfoundland Power proposes effective January 1, 2013 to (i) calculate annual defined benefit pension expense for regulatory purposes in accordance with U.S. GAAP and (ii) amortize the recovery of the forecast regulatory asset of approximately $12.4 million over 15 years.[138]

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[135] In the evidence filed in November 2011 by Newfoundland Power in support of its application to adopt U.S. GAAP for regulatory purposes, annual defined benefit pension expense calculated under U.S. GAAP was indicated to be *higher* than under Canadian GAAP until 2018 (see Table 1, page 5, Evidence of Newfoundland Power Inc. November 10, 2011). The lower pension expense calculated under U.S. GAAP is the result of updated actuarial valuation for the Company's defined benefit pension plan. The actuarial valuation as at December 31, 2011, is the basis for Table 3-18 on page 3-46; the actuarial valuation as at December 31, 2008 was the basis for the Company's November 2011 evidence. The actuarial valuation as at December 31, 2011 provides the most current demographic data related to the calculation of pension expense. This data affects the period over which the cost of defined pension benefits may be attributed (for an explanation of how the attribution period affects annual defined benefit pension expense under U.S. and Canadian GAAP, see Evidence of Newfoundland Power Inc. November 10, 2011, page 4, *et. seq*.).

[136] In Order No. P.U. 11 (2012), the Board approved a definition of an *Employee Future Benefits Regulatory Assets and Liabilities Account* which requires these differences to be effectively recognized in the calculation of the Company's rate base. In the evidence filed in November 2011 by Newfoundland Power in support of its application to adopt U.S. GAAP for regulatory purposes, the Company indicated the treatment of annual pension expense variances arising from the adoption of U.S. GAAP could be reviewed by the Board in the Company's next general rate application (see Evidence of Newfoundland Power Inc. November 10, 2011, page 11, line 21 *et. seq*.).

[137] The amount of $12.4 million includes the balance of $11.8 million as at December 31, 2011 (see Footnote 133) and the difference of $0.6 million in 2012.

[138] An amortization period for recovery of 15 years was found by the Board to be reasonable for the recovery of the OPEBs regulatory asset created upon the adoption of the accrual method for OPEBs accounting in 2011 (see Order No. P.U. 31 (2010), page 5).

Table 3-19 shows the effect of Newfoundland Power's proposed changes to annual defined benefit pension expense calculation for 2013 to 2017.

Table 3-19
Defined Benefit Pension Expense
Current and Proposed
2013F to 2017F
($000s)

	2013F	2014F	2015F	2016F	2017F
Current	11,150	10,566	8,602	7,072	6,027
Proposed					
U.S. GAAP	9,801	9,169	7,328	5,723	4,549
Amortization of Regulatory Asset[139]	824	824	824	824	824
Total Proposed	10,625	9,993	8,152	6,547	5,373
Difference	**(525)**	**(573)**	**(450)**	**(525)**	**(654)**

The proposed annual defined benefit pension expense under U.S. GAAP, including the proposed amortization of the regulatory asset, is forecast to be lower than the current method by approximately $0.5 to $0.7 million through 2017.

Newfoundland Power's proposals for future accounting for annual defined benefit pension expense will reduce the Company's revenue requirements to be recovered from customers. In addition, it will eliminate the single remaining difference between financial reporting and regulatory reporting which arose upon the Company's adoption of U.S. GAAP. This will enhance ongoing regulatory transparency.

3.4.3 Conservation Program Costs

In the 2013 – 2014 test period, Newfoundland Power intends to develop and implement an expanded customer energy conservation programming portfolio. This is expected to increase

[139] $12.4 million divided by 15 years = $0.8 million.

conservation costs by approximately $2.4 million per year by 2014. The benefits of this increased programming are cumulative and enduring.[140]

Currently, Newfoundland Power fully expenses conservation costs in the year in which they are incurred.[141] Given the cumulative and enduring nature of the benefits of such programming, Newfoundland Power and Hydro have considered the means of recovering these programming costs in its reassessment of the current portfolio of customer energy conservation programs. In this Application, Newfoundland Power is proposing that, commencing in 2013, the recovery of customer energy conservation program costs be spread over 7 years.[142] This is reasonably consistent with public utility practice related to conservation cost recovery which indicates recovery of conservation program costs over periods from 5 to 15 years.[143]

A proposed *Conservation and Demand Management Cost Deferral Account Definition* is contained in *Volume 2, Exhibits & Supporting Materials, Exhibit 7*.

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[140] These increased costs and benefits are described in detail in *Section 2.2.2 Conservation Programming* at page 2-13 to page 2-18.

[141] Current recognition of conservation program costs has existed since Order No. P.U. 43 (2009). Prior to this, costs associated with *Five-Year Energy Conservation Plan: 2008 – 2013* were deferred for future recovery by Order No. P.U. 13 (2009). In Order No. P.U. 6 (1991), the Board first authorized five year deferral of demand side management costs. This deferral practice was discontinued as the result of the Board's Order No. P.U. 7 (1996-97).

[142] Recovery of customer energy conservation programming costs is proposed to be achieved by annual amortizations recovered through the Company's Rate Stabilization Plan. Newfoundland Power is proposing that annually recurring general conservation costs associated with the provision of general customer information, community outreach, and planning will continue to be recognized in the year in which they are incurred.

[143] Currently, the British Columbia Utilities Commission requires conservation program costs to be amortized and recovered over 10 year or 15 year periods. Prior to its adoption of International Financial Reporting Standards in 2012, Manitoba Hydro recovered conservation program costs over variable periods of up to 15 years based upon the conservation technologies implemented. Prior to the P.E.I. Office of Energy Efficiency assuming administration of conservation programs in March 2011, Maritime Electric Co. Ltd. amortized conservation costs over a 5 year period.

Table 3-20 shows the *pro forma* impacts of the proposed annual customer energy conservation program cost deferrals and amortizations for the 10 years from 2013 through 2022.[144]

Table 3-20
Proposed Conservation Program Costs
***Pro forma* Forecast Deferrals and Amortizations**
2013 to 2022
($000s)

	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Deferral	(3,065)	(4,401)	(4,762)	(4,711)	(4,711)	(4,711)	(4,711)	(4,711)	(4,711)	(4,711)
Amortization	-	438	1,067	1,747	2,420	3,093	3,766	4,439	4,674	4,718

Forecast annual customer energy conservation program costs are relatively stable through the 10 year period.[145] Forecast annual amortizations, which will be recovered in customer rates through the annual RSA adjustment, will increase through the period.[146] This dynamic of increasing recovery is consistent with the cumulative nature of benefits associated with customer energy conservation programming.

The proposed deferral and recovery of customer energy conservation program costs over 7 years will reduce 2013 and 2014 revenue requirements.[147]

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[144] For *pro forma* purposes, from 2017 through 2022, customer energy conservation program costs are forecast to remain at the forecast 2016 amount of $4,711,000. Program costs subsequent to 2016 will be subject to planning similar to that contained in the *Five-Year Energy Conservation Plan: 2012 – 2016.*

[145] This forecast stability over the 10 year period essentially reflects the forecast stable customer energy conservation program costs of $4.4 to $4.7 million per year from 2014 to 2022. However, if program costs subsequent to 2016 vary materially from current forecast, the impact of the variation on customer rates will be moderated by the deferral and seven year amortization.

[146] Because customer energy conservation program costs are proposed to be recovered in customer rates through the RSA, they will be reflected in annual RSA factor adjustments as opposed to revenue requirements which are reflected in the Company's base rates.

[147] 2013 revenue requirements are reduced by approximately $2.9 million ($3.1 million – rate base effects of $0.2 million); 2014 revenue requirements are reduced by approximately $4.0 million ($4.4 million – rate base effects of $0.4 million). Current recognition of these customer energy conservation program costs in the year they are incurred would increase 2013 revenue requirements by approximately $3.1 million, or 0.5% ($3.1 million ÷ $601.6 million = 0.0052) and 2014 revenue requirements by approximately $4.4 million, or 0.7% ($4.4 million ÷ $618.8 million = 0.0071).

3.4.4 Weather Normalization Reserve

Newfoundland Power's Weather Normalization Reserve normalizes the effects of weather and hydrology on the Company's sales and power supply cost.[148] Balances reflecting annual transfers to and from the Weather Normalization Reserve are considered annually by the Board and potential disposition of accrued balances in the Weather Normalization Reserve are typically reviewed by the Board at general rate applications.[149]

The Weather Normalization Reserve is the only regulatory mechanism governing the Company which does not provide for timely recovery or credit of balances. Outstanding balances have, however, as a result of general rate applications, been continually recovered through amortizations in customer rates for each year from 2003 to 2012.[150] These amortizations have been the result of matters such as changes in wholesale power rates from Hydro and changes in tax rates applicable to Newfoundland Power.

It is typical for regulatory mechanisms such as the Weather Normalization Reserve to include provision for timely recovery or rebate of balances.[151] In this Application, Newfoundland Power is proposing that annual balances outstanding in the Weather Normalization Reserve be

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148 The Weather Normalization Reserve was approved in Order Nos. P.U. 32 (1968) and P.U. 1 (1974).

149 For approvals of balances following annual transfers see, for example, Order Nos. P.U. 9 (2011) and P.U. 19 (2012). For approvals of disposition of accrued balances in a general rate application see, for example, Order No. P.U. 19 (2003), where the Board approved recovery of approximately $5.6 million (on an after tax basis) through customer rates over a five year period and Order No. P.U. 32 (2007), where the Board approved recovery of approximately $6.8 million (on an after tax basis) through customer rates over a five year period.

150 As a result of Order No. P.U 19 (2003), approximately $1.7 million per year was amortized in customer rates for the period 2003 to 2007. As a result of Order No. P.U 32 (2007), approximately $2.1 million per year was amortized in customer rates for the period 2008 to 2012.

151 For example, Hydro's Rate Stabilization Plan and Newfoundland Power's Rate Stabilization Account both have specific provisions for recovery of balances through mid-year adjustments to customer rates. Similarly, weather normalization mechanisms in place for Pacific Northern Gas and FortisBC Energy provide for recovery of outstanding balances.

recovered from, or credited to, customers as part of the Company's annual RSA adjustment to customer rates on July 1 of each year.[152]

The proposed change in the treatment of *future* Weather Normalization Reserve balances will not directly affect 2013 – 2014 revenue requirements.[153] However, to accommodate the implementation of this proposal, the Company is proposing amortization of the outstanding year-end 2011 balance in the Weather Normalization Reserve which will reduce 2013 – 2014 revenue requirements.[154]

3.4.5 Summary of Proposed Accounting Changes

Table 3-21 summarizes the effect of the proposed accounting changes described in this section upon 2013 – 2014 test period revenue requirements.

Table 3-21
Proposed Accounting Changes
***Pro forma* Revenue Requirements Impact**
2013F to 2014F
($000s)

	2013F	**2014F**
Depreciation Expense[155]	705	730
Pension Expense[156]	(525)	(573)
Conservation Programming[157]	(3,065)	(4,401)
Total	**(2,885)**	**(4,244)**

152 It is proposed that *year end* balances, including the year end 2012 balance, will be recovered in the Rate Stabilization Adjustment commencing the following July 1.

153 Customer rates have three components: base rates, an RSA factor, and a MTA factor. Because future Weather Normalization Reserve balances are proposed to be recovered, or credited, in customer rates through the RSA, they are reflected in the annual RSA factor. Revenue requirements are reflected in the Company's base rates.

154 See *Section 3.5.3 Weather Normalization Reserve*, page 3-55.

155 See Table 3-17.

156 See Table 3-19.

157 See Table 3-20. The amortization indicated in Table 3-20 in 2014 of the forecast $438,000 does not affect 2014 revenue requirements because this amortization is proposed to be recovered through the Rate Stabilization Plan, effective July 1, 2014.

The proposed accounting changes described in this section will reduce Newfoundland Power's revenue requirements by approximately $2.9 million in 2013 and approximately $4.2 million in 2014.

3.5 REGULATORY AMORTIZATIONS

This section of the evidence reviews regulatory deferrals and amortizations through 2015.

In this Application, Newfoundland Power is proposing 3 year amortizations for (i) cost recovery deferrals approved in 2011 and 2012; (ii) third party hearing costs associated with this Application; (iii) the year end 2011 balance in the Weather Normalization Reserve; and (iv) a 2013 revenue shortfall resulting from a forecast March 1, 2013 implementation of revised customer rates.

The proposals included in this Application related to regulatory deferrals and amortizations will reduce the Company's revenue requirements by approximately $0.2 million in 2013 and increase revenue requirements by approximately $0.8 million in 2014.

3.5.1 2011 to 2012 Deferrals

In Order No. P.U. 30 (2010), the Board approved the deferred recovery by Newfoundland Power of $2.4 million in 2011 costs. In Order No. P.U. 22 (2011), the Board approved the deferred recovery by Newfoundland Power of $2.4 million in 2012 costs. In Order No. P.U. 17 (2012), the Board approved the deferred recovery by Newfoundland Power of $2.5 million in 2012 costs as part of its determination of the Company's 2012 cost of capital. In this Application, Newfoundland Power is proposing to amortize the recovery of these 2011 and 2012 deferrals in equal parts over a 3 year period commencing in 2013.

Table 3-22 shows the revenue requirement impacts of Newfoundland Power's cost deferrals in 2011 and 2012 and the recovery of these deferrals from 2013 to 2015P.

Table 3-22
2011/2012 Cost Recovery Deferrals
Proposed Amortizations
***Pro forma* Revenue Requirement Impact**
2011 to 2015
($000s)

	2011	**2012**	**2013**	**2014**	**2015**
2010 Amortization Expiry	(2,363)	(2,363)	1,575	1,575	1,575
2012 Cost of Capital	-	(2,487)	829	829	829
Revenue Requirement Impact	**(2,363)**	**(4,850)**	**2,404**	**2,404**	**2,404**

3.5.2 Hearing Costs

Newfoundland Power estimates approximately $1.25 million will be incurred by the Board and the Consumer Advocate and billed to the Company related to this Application. Newfoundland Power is proposing these costs be recovered in customer rates evenly over a 3 year period from 2013 to 2015.[158]

[158] In the past, the Board has ordered recovery of Application costs over a 3 year period on a number of occasions (see Order Nos. P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), P.U. 32 (2007), and P.U. 43 (2009)).

Table 3-23 shows the revenue requirement impact of (i) amortization of third party hearing costs associated with *Newfoundland Power's 2010 General Rate Application*, and (ii) the proposed amortization of third party hearing costs associated with its 2013 – 2014 general rate application from 2013 to 2015.

Table 3-23
Amortization of Hearing Costs
***Pro forma* Revenue Requirement Impact**
2011 to 2015
($000s)

	2011	**2012**	**2013**	**2014**	**2015**
2010 General Rate Application	253	250	-	-	-
2013/2014 General Rate Application	-	-	417	417	416
Revenue Requirement Impact	**253**	**250**	**417**	**417**	**416**

3.5.3 Weather Normalization Reserve

In this Application, Newfoundland Power is proposing that the outstanding year-end balance for 2011 in the Weather Normalization Reserve of approximately $5.0 million due to customers be amortized over three years commencing in 2013. This will accommodate the proposed accounting changes to the Weather Normalization Reserve.[159] This will result in an annual amortization of $2.3 million from 2013 through 2015.[160]

3.5.4 2013 Revenue Shortfall

Based upon a March 1, 2013 implementation, customer rates designed to recover the 2014 revenue requirement would result in $980,000 shortfall in recovering the 2013 revenue requirement. The Company is proposing a revenue amortization to recover this shortfall.

[159] The proposed accounting changes to the Weather Normalization Reserve are described in *Section 3.4.4 Weather Normalization Reserve*.

[160] The year end 2011 Weather Normalization Reserve balance of $5,020,000 is an *after-tax* balance conceptually due to customers. The equivalent pre-tax value is $7,005,000 ($7,005,000 ÷ 3 = $2,335,000).

Including this amortization in customer rates allows the 2013 revenue shortfall to be recovered from customers over the period March 1, 2013 to December 31, 2015.[161]

3.5.5 Summary of Amortizations

Table 3-24 summarizes the effect of the regulatory deferrals and amortizations described in this section, including the impact of these deferrals and amortizations upon 2013 – 2014 test period revenue requirements.

Table 3-24
Amortization of Regulatory Deferrals
***Pro forma* Revenue Requirement Impact**
2011 to 2015
($000s)

	2011	**2012**	**2013**	**2014**	**2015**
2011/12 Cost Deferrals[162]	(2,363)	(2,363)	1,575	1,575	1,575
2012 Cost of Capital Deferral[162]	-	(2,487)	829	829	829
Hearing Costs[163]	253	250	417	417	416
Weather Normalization Reserve[164]	2,101	2,101	(2,335)	(2,335)	(2,335)
2013 Revenue Shortfall[165]	-	-	(692)	346	346
Revenue Requirement Impact	**(9)**	**(2,499)**	**(206)**	**832**	**831**

The proposed regulatory deferrals and amortizations described in this section will reduce Newfoundland Power's revenue requirements by approximately $0.2 million in 2013 and increase revenue requirements by approximately $0.8 million in 2014.

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161 To enable proposed customer rates to provide the revenue requirement for both 2013 and 2014, amortization of $288,240 in 2013, and $345,888 in each of 2014 and 2015 were included in the revenue requirements used in designing rates.

162 See Table 3-22.

163 See Table 3-23.

164 For 2011 – 2012, see *Section 3.2.2 Power Supply,* Table 3-3; for 2013 – 2015, see *Section 3.5.3 Weather Normalization Reserve*.

165 For 2013, the revenue requirement impact is $980,000 – (10 x $28,824) = $691,760; for 2014 and 2015, the impact is $28,824 x 12 = 345,888.

SECTION 4: RATE BASE & REVENUE REQUIREMENTS

4.1 OVERVIEW

This section of the evidence addresses the Company's forecast 2013 and 2014 average rate base and forecast 2013 and 2014 revenue requirements.

Based on the Company's proposals in this Application, forecast 2013 and 2014 average rate base are approximately $918 million and $954 million, respectively.

Based upon the Company's proposals in this Application, forecast 2013 and 2014 revenue requirements are approximately $602 million and approximately $619 million, respectively.

To generate the increase in revenue necessary to meet the Company's forecast revenue requirements in 2013 and 2014, an average increase in current customer rates of approximately 6.0% effective March 1, 2013 will be required.

4.2 2013 AND 2014 RATE BASE

Exhibit 8, in *Volume 2, Exhibits & Supporting Materials*, shows Newfoundland Power's forecast 2013 and 2014 average rate base.

Newfoundland Power's forecast 2013 and 2014 average rate base, as set out in this Application, including rate base allowances, is calculated in accordance with Board orders and regulatory practice.[1]

[1] The report *2013 and 2014 Rate Base Allowances* is found in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 3.*

The Company's forecast 2013 and 2014 average rate base are approximately $918 million and $954 million, respectively.

Changes to the Company's average rate base are principally the result of (i) plant investment, which includes annual capital expenditures;[2] and (ii) depreciation expense.[3]

The forecast 2013 and 2014 average rate base include the Company's forecast capital expenditures for 2012 which were approved in Order Nos. P.U. 26 (2011), P.U. 7 (2012), P.U. 8 (2012) and P.U. 28 (2012). The calculation of the Company's forecast 2013 and 2014 average rate base also reflects forecast 2013 and 2014 capital expenditures of approximately $81 million and $83 million, respectively.[4]

4.3 2013 AND 2014 REVENUE REQUIREMENTS

Exhibit 9, in *Volume 2, Exhibits & Supporting Materials*, shows Newfoundland Power's 2013 and 2014 forecast revenue requirements.[5]

The Company revenue requirements used to establish electricity rates are forecast to be approximately $602 million in 2013 and approximately $619 million in 2014.

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2 Each year, the Company's capital expenditures for the following year are considered and approved by the Board. Further detail on the capital forecast is provided in the *2013 Capital Budget Application* filed on June 28, 2012.

3 Annual depreciation expense is currently calculated using the composite depreciation rates approved by the Board in Order No. P.U. 43 (2009). The Company is proposing revised composite depreciation rates based on the *2010 Depreciation Study*, found in *Volume 3, Expert Evidence & Studies, Tab 3*. See *Section 3.4.1 2010 Depreciation Study*.

4 The forecast capital expenditures for 2013 and 2014 are described in detail in the *2013 Capital Budget Application* filed on June 28, 2012. The Board is currently reviewing that Application.

5 *Exhibit 9* in *Volume 2, Exhibits & Supporting Materials*, compares the 2013 and 2014 revenue requirements in the absence of the proposals contained in this Application to the revenue requirements proposed in this Application.

4.3.1 Summary of Revenue Requirements

Table 4-1 shows a summary of Newfoundland Power's 2013 and 2014 forecast revenue requirements and the revenue required to be recovered from customer rates.

Table 4-1
Summary of 2013 and 2014 Revenue Requirements
($000s)

	2013	**2014**
Power Supply Cost	390,257	397,857
Operating Costs[6]	53,641	55,406
Employee Future Benefit Costs	22,650	22,058
Regulatory Amortizations	1,712	2,750
Depreciation	46,647	48,291
Income Taxes[6]	18,361	18,740
Return on Rate Base	79,344	81,838
Revenue Requirements	**612,612**	**626,940**
Deductions[7]	(11,061)	(8,094)
Revenue Requirements from Rates	**601,551**	**618,846**

4.3.2 Costs and Depreciation

Table 4-2 shows forecast 2013 and 2014 power supply costs.

Table 4-2
2013 and 2014 Power Supply Costs
($000s)

	2013	**2014**
Power Supply Cost	392,547	404,686
Elasticity Impact[8]	(2,290)	(6,829)
Proposed	**390,257**	**397,857**

6 For revenue requirement purposes, operating costs and income taxes do not include non-regulated expenses.
7 See *Volume 2, Exhibits & Supporting Materials, Exhibit 9,* line 20.
8 Newfoundland Power's methodology for forecasting elasticity effects is consistent with that used for the customer and energy forecast accepted by the Board in Order No. P.U. 32 (2007).

Table 4-3 shows forecast 2013 and 2014 operating costs.[9]

Table 4-3
2013 and 2014 Operating Costs
($000s)

	2013	**2014**
Existing	56,244[10]	58,903[11]
2013 Hearing Costs[12]	417	417
Conservation Costs[13]	(3,065)	(3,963)
Change in GEC[14]	45	49
Proposed	**53,641**	**55,406**

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9 *Exhibits 1 and 2* in *Volume 2, Exhibits & Supporting Materials*, show the forecast gross operating costs for 2013 and 2014. These are reviewed in detail in *Section 2.3 2013 and 2014 Operating and Capital Costs*.

10 Existing operating costs in 2013 include (i) gross operating cost of approximately $59.1 million, see *Volume 2, Exhibits & Supporting Materials*, *Exhibit 1*, line 25 and *Exhibit 2*, line 30; *plus* a $0.3 million amortization of conservation costs approved by the Board in Order No. P.U. 43 (2009); *less* (ii) deferred recovery of $0.1 million related to implementation of the Optional Seasonal Rate and TOD Rate study approved by the Board in Order No. P.U. 8 (2011); and approximately $3.1 million in GEC.

11 Existing operating costs in 2014 include (i) gross operating cost of approximately $62.0 million, see *Volume 2, Exhibits & Supporting Materials, Exhibit 1*, line 25 and *Exhibit 2*, line 30; *plus* the deferred recovery of $40,000 related to implementation of the Optional Seasonal Rate and the TOD Rate study approved by the Board in Order No. P.U. 8 (2011); *less* (ii) approximately $3.1 million in general expenses capitalized.

12 The Company expects to incur additional costs of $1,250,000 in 2013 related to the 2013 general rate application. The Company is proposing to defer and recover these costs over a 3 year period beginning in 2013. See *Section 3.5.2 Hearing Costs*.

13 Beginning in 2013, the Company is proposing the deferred recovery and amortization over a 7 year period of certain costs related to the *Five Year Energy Conservation Plan: 2012-2016*. See *Section 3.4.3 Conservation Program Costs*.

14 Beginning in 2013, the Company is proposing to adopt U.S. GAAP for the determination of employee future benefit costs. This proposal will reduce forecast pension plan costs in 2013 and 2014 resulting in a forecast reduction to GEC. See *Section 3.4.2 Employee Future Benefit Costs*.

Table 4-4 shows forecast 2013 and 2014 employee future benefits costs.

Table 4-4
2013 and 2014 Employee Future Benefits Costs
($000s)

	2013	**2014**
Pension Plans[15]	12,714	12,195
OPEBs[15]	10,461	10,436
	23,175	22,631
Accounting Change[16]	(525)	(573)
Proposed	**22,650**	**22,058**

Table 4-5 shows forecast 2013 and 2014 deferred cost recoveries and regulatory amortizations.

Table 4-5
2013 and 2014 Deferred Cost Recoveries
and Regulatory Amortizations
($000s)

	2013	**2014**
2012 Cost of Capital Amortization[17]	829	829
2010 Regulatory Amortizations[18]	1,575	1,575
2013 Revenue Shortfall Deferral[19]	(980)	-
2013 Revenue Shortfall Amortization[20]	288	346
Proposed	**1,712**	**2,750**

15 The Company's employee future benefits costs are reviewed in detail in *Section 3.4.2 Employee Future Benefits Costs*.

16 Beginning in 2013, the Company is proposing to adopt U.S. GAAP for the determination of employee future benefits costs. The Company's proposals with respect to employee future benefits are described in *Section 3.4.2 Employee Future Benefits Costs*.

17 In Order No. P.U. 17 (2012), the Board approved the deferred recovery of approximately $2.5 million in costs related to the *2012 Cost of Capital Application*. The Company is proposing to recover these costs over a 3 year period beginning in 2013. See *Section 3.5.1 2011-2012 Deferrals* and *3.5.5 Summary of Amortizations*.

18 In Order Nos. P.U. 30 (2010) and P.U. 22 (2011), the Board approved the deferred recovery of approximately $2.3 million in costs for each of 2011 and 2012 related to the expiry in 2010 of certain regulatory amortizations. The Company is proposing to recover these costs over a 3 year period beginning in 2013. See *Section 3.5.1 2011-2012 Deferrals*.

19 The Company is proposing deferral of an approximately $1 million revenue shortfall in 2013. The revenue shortfall is due to timing differences resulting from the March 1, 2013 customer rate implementation date. See *Section 3.5.4 2013 Revenue Shortfall*.

20 The Company is proposing to amortize the 2013 revenue shortfall over a 34 month period, beginning on March 1, 2013. See *Section 3.5.4 2013 Revenue Shortfall*.

Table 4-6 shows forecast 2013 and 2014 depreciation costs and related amortization.

Table 4-6
2013 and 2014 Depreciation Cost
and Related Amortization
($000s)

	2013	**2014**
Existing	45,942	47,561
2010 Depreciation Study Impact[21]	705	730
Proposed Depreciation	**46,647**	**48,291**

Table 4-7 shows forecast 2013 and 2014 income taxes.

Table 4-7
2013 and 2014 Income Taxes
($000s)

	2013	**2014**
Existing	13,102	12,328
Tax Effects of Application Proposals[22]	5,259	6,412
Proposed	**18,361**	**18,740**

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21 The Company is proposing to implement the depreciation rates from the *2010 Depreciation Study* effective January 1, 2013 and to amortize the accumulated reserve variance of $2.6 million over the composite remaining life of the assets.

22 The tax effects of the Application proposals are as follows:

	($000s)	
	2013	**2014**
Increase in Forecast Revenue from Rates, *Exhibit 9*, line 22	27,818	34,207
Transfers to the RSA Included in Existing Rates, *Exhibit 9*, lines 18 and 19	(19,786)	(23,170)
Increase in Taxable Revenue	8,032	11,037
Reduction in Tax Deductible Expenses (purchased power, operating, interest)	12,106	13,509
Increase in Taxable Income	20,138	24,546
Tax Rate	29.0%	29.0%
Increase in Cash Income Taxes	5,840	7,118
Reduction in Future Income Taxes	(581)	(706)
Increase in Total Income Taxes	**5,259**	**6,412**

4.3.3 Return on Rate Base

Exhibit 10, in *Volume 2, Exhibits & Supporting Materials*, shows Newfoundland Power's proposed 2013 and 2014 return on rate base.

Table 4-8 summarizes the proposed 2013 and 2014 return on rate base and rate of return on rate base.

Table 4-8
2013 and 2014 Return on Rate Base
($000s)

	2013	**2014**
Forecast Average Rate Base	917,891[23]	954,123[24]
Forecast Regulated Returns		
Debt	35,421	36,301
Preferred Equity	566	566
Common Equity	43,357	44,971
Return on Rate Base	**79,344**	**81,838**
Rate of Return on Rate Base (%)	**8.64** [25]	**8.58** [26]

23 2013 forecast average rate base is shown in *Volume 2, Exhibits & Supporting Materials, Exhibit 8*, line 30.
24 2014 forecast average rate base is shown in *Volume 2, Exhibits & Supporting Materials, Exhibit 8*, line 30.
25 The forecast rate of return on rate base for 2013 is calculated as ($79,344,000/$917,891,000= 8.64%), as shown in *Volume 2, Exhibits & Supporting Materials, Exhibit 10*, page 1 of 2, line 23.
26 The forecast rate of return on rate base for 2014 is calculated as ($81,838,000/$954,123,000= 8.58%), as shown in *Volume 2, Exhibits & Supporting Materials, Exhibit 10*, page 2 of 2, line 23.

4.3.4 Deductions and Revenue Amortizations

Table 4-9 shows the forecast 2013 and 2014 deductions from revenue requirements.

Table 4-9
2013 and 2014 Deductions from Revenue Requirements
($000s)

	2013	2014
Other Revenue	(5,163)[27]	(5,247)[28]
Weather Normalization Reserve[29]	(2,335)	(2,335)
Transfers to the RSA	(3,575)[30]	(524)[31]
Interest on Security Deposits[32]	12	12
Proposed	**(11,061)**	**(8,094)**

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27 Existing other revenue – interest on RSA ($5,430,000 - 267,000= 5,163,000).

28 Existing other revenue – interest on RSA ($5,340,000 - 93,000= 5,247,000).

29 In this Application, the Company is proposing, beginning in 2013, a 3 year amortization of the 2011 balance in the Weather Normalization Reserve. See *Section 3.4.4 Weather Normalization Reserve*.

30 The 2013 transfers to the RSA include a $3,497,000 balance in the Energy Supply Cost Variance Reserve at March 1, 2013 and $78,000 related to the Optional Seasonal and TOD Rate study. The deferred recovery of revenues and costs associated with the Optional Seasonal and TOD Rate study was approved by the Board in Order No. P.U. 8 (2011).

31 The 2014 transfer to the RSA is due to (i) $438,000 related to the proposed amortization of conservation program costs and (ii) $86,000 related to the deferred recovery of revenues associated with Optional Seasonal and TOD Rate study.

32 Interest on customer security deposits is not included in the determination of revenue requirements.

4.3.5 Required Revenue Increase

Table 4-10 shows the forecast increase in revenue from rates of approximately $30 million required to meet the Company's proposed 2013 revenue requirement and approximately $41 million required to meet the Company's proposed 2014 revenue requirement.

Table 4-10
2013 and 2014 Required Revenue Increases
($000s)

	2013	2014
2014 Proposed Revenue From Rates	**601,551**	**618,846**
Revenue From Existing Rates	(573,733)	(584,639)
Elasticity Impacts[33]	2,198	6,326
Required Increase in Revenue from Rates	**30,016**	**40,533**

The increase in revenue from rates for 2014 requires an average increase in current customer rates of 6.0%, effective March 1, 2013.

[33] See *Volume 2, Exhibits & Supporting Materials, Exhibit 11*, line 1.

SECTION 5: CUSTOMER RATES

5.1 OVERVIEW

The number of customers served by Newfoundland Power is forecast to increase by 1.3% in each of 2013 and 2014. Energy sales are forecast to grow by 1.2% in each year. Demand is forecast to increase by 1.6% in 2013 and 1.3% in 2014.

Newfoundland Power's rate change plan in this Application targets revenue to cost ratios in a range of 90% to 110% for all classes of service and implements rate design changes in accordance with the Retail Rate Review.

In this Application, the Company proposes a 6.0% average increase in customer rates effective March 1, 2013. For residential customers, the average increase will be approximately 7.2%.

This evidence also outlines the results of the Company's review of supply cost mechanisms and proposed changes to the Rate Stabilization Clause to provide for recovery of customer energy conservation program costs and annual transfers to the Weather Normalization Reserve through the RSA.

5.2 CUSTOMER, ENERGY AND DEMAND FORECAST

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

This section of evidence reviews Newfoundland Power's 2013 and 2014 customer, energy and demand forecast.

5.2.1 Customers Served

Newfoundland Power is the largest distributor of electricity on the Island interconnected grid and is responsible for retail pricing for the approximately 270,000 customers served by the grid.[1]

Table 5-1 provides the forecast percentage of customers and sales for each rate class.

Table 5-1
Newfoundland Power Customer Base
2014 Forecast

Rate	Class of Service	% of Total Customers	% of Total Energy Sales
1.1	Domestic	87.0	60.9
2.1	General Service 0-10 kW	4.8	1.7
2.2	General Service 10-100 kW (110 kVA)	3.6	11.9
2.3	General Service 110-1000 kVA	0.5	16.4
2.4	General Service 1000 kVA and Over	-[2]	8.6
4.1	Street and Area Lighting Service	4.1	0.5
	Total	**100.0**	**100.0**

The customers served by Newfoundland Power are predominantly Domestic customers. Approximately 61% of Newfoundland Power's annual energy sales are to Domestic customers.

5.2.2 Forecast

Newfoundland Power's *Customer, Energy and Demand Forecast* is found in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 4.*

[1] Hydro serves approximately 23,500 rural customers on the Island interconnected grid. Those 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.

[2] The 65 customers in Rate 2.4 comprise less than 0.01% of total customers.

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

Table 5-2 shows the Company's forecast number of customers for 2012, 2013 and 2014.

Table 5-2
Forecast Number of Customers
2012F to 2014F

	2012F	**2013F**	**2014F**
Domestic	217,707	220,743	223,677
General Service			
0-10 kW	12,352	12,400	12,444
10-100 kW (110 kVA)	9,071	9,186	9,300
110-1000 kVA	1,150	1,164	1,179
1000 kVA and Over	66	67	65
Total General Service	22,639	22,817	22,988
Street and Area Lighting	10,391	10,499	10,602
Total Customers	**250,737**	**254,059**	**257,267**

The number of customers is forecast to increase by approximately 1.3% annually in both 2013 and 2014.

[3] See Appendices B and C to the *Customer, Energy and Demand Forecast, Volume 2, Exhibits & Supporting Materials, Reports, Tab 4*.

Table 5-3 shows the Company's forecast energy sales for 2012, 2013 and 2014.

Table 5-3
Energy Sales Forecast
2012F to 2014F
(GWh)

	2012F	**2013F**	**2014F**
Domestic	3,472.0	3,520.3	3,545.7
General Service			
0-10 kW	96.2	97.8	98.6
10-100 kW (110 kVA)	677.7	685.2	693.6
110-1000 kVA	935.2	941.1	955.8
1000 kVA and Over	463.6	475.6	497.9
Total General Service	2,172.7	2,199.7	2,245.9
Street and Area Lighting	35.9	30.9	31.1
Total Energy Sales	**5,680.6**	**5,750.9**	**5,822.7**

Energy sales are forecast to increase by approximately 1.2% annually in both 2013 and 2014.[4]

Table 5-4 shows the Company's forecast demand for 2012, 2013 and 2014.

Table 5-4
Demand Forecast
2012F to 2014F
(MW)

	2012F	**2013F**	**2014F**
Native Peak[5]	1,330.8	1,352.4	1,369.4
Purchased[6]	1,212.9	1,234.5	1,251.5

4 The sales forecast includes elasticity effects of 24.6 GWh in 2013 and 70.4 GWh in 2014 as a result of the proposed March 1, 2013 average rate increase of 6.0%.

5 Native peak is the maximum demand served by Newfoundland Power. The 2012 native peak reflects the forecast for the winter period of December 2012 to March 2013.

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

Demand is forecast to increase by approximately 1.6% in 2013 and 1.3% in 2014. Demand purchases from Hydro are forecast to increase by 1.8% in 2013 and 1.4% in 2014.[7]

5.3 RATE CHANGE PLAN

This section of the evidence outlines the basis for the customer rate proposals in this Application.

The Company's rate change plan proposes to (i) vary the rate increase by customer rate class so cost recovery for each class is within the target revenue to cost ratio range of 90% to 110%, and (ii) to implement changes in customer rate designs in accordance with the Retail Rate Review.

5.3.1 Cost of Service

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

The Company has prepared an embedded cost of service study to reflect 2011 costs (the "Cost of Service Study"). The Cost of Service Study is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 5*.

[7] Because forecast growth in demand is supplied by Hydro, the forecast increase in purchased demand is higher on a percentage basis than the forecast increase in native peak demand.

Table 5-5 shows the current revenue to cost ratio for each rate class as indicated by the Cost of Service Study.

Table 5-5
Cost of Service Study Results

Rate	**Class of Service**	**Revenue to Cost Ratio %**
1.1	Domestic	95.0
2.1	General Service 0-10 kW	113.5
2.2	General Service 10-100 kW (110 kVA)	113.3
2.3	General Service 110-1000 kVA	109.5
2.4	General Service 1000 kVA and Over	104.6
4.1	Street and Area Lighting	101.8

Maintaining revenue to cost ratios for each class within a range of 90% to 110% has been an accepted approach to avoiding undue cross-subsidization among the various classes.[8]

The revenue to cost ratios for the Rate 2.1 class (0-10 kW) and Rate 2.2 class (10-100 kW) are greater than 110%. The Company's rate proposals in this Application were developed, in part, to bring the revenue to cost ratios for those classes within the target range.[9] This indicates that a higher than average increase will be required for Rate 1.1.[10]

[8] This is consistent with the views of the Board as expressed in Order No. P.U. 7 (1996-97), which states: "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%, …".

[9] The rate proposals were also developed to implement changes indicated in the Retail Rate Review. At *Newfoundland Power's 2010 General Rate Application*, the Company proposed completing the cost recovery adjustments to achieve the target revenue to cost ratios for Rates 2.1 and 2.2 coincident with implementation of structural changes to these rates resulting from the Retail Rate Review. See *Newfoundland Power 2010 General Rate Application*, Evidence, page 5-9, lines 13, *et. seq*..

[10] Since the Domestic class accounts for approximately 61% of overall sales and is the only class with a revenue to cost ratio less than 100%, that class will almost inevitably receive an above average increase if a material reduction in the revenue to cost ratio in another class is required. This is practically required to allow for recovery of the total revenue requirement and address the over-recovery in classes General Service 0-10 kW and 10-100 kW.

Table 5-6 provides the March 1, 2013 relative rate changes by class and the resulting *pro forma* revenue to cost ratios resulting from the rate proposals in the Application.

Table 5-6
Proposed Relative Rate Changes by Class

Rate	Class	Relative to Average	*Pro forma* Revenue to Cost Ratio %
1.1	**Domestic**	**1.2% above**[11]	**96.1**
2.1[12]	**General Service 0-100 kW (110 kVA)**	**5.4% below**	**107.6**
2.3	General Service 110-1000 kVA	Equal	109.5
2.4	General Service 1000 kVA and Over	Equal	104.6
4.1	Street and Area Lighting	Equal	101.8

The proposed changes in customer rates will result in a reduction in the revenue to cost ratio for the proposed merged Rate 2.1 class.[13] The revenue to cost ratio for Rate 1.1 will increase from 95% to approximately 96%.[14] After implementation of the Company's rate proposals, the *pro forma* revenue to cost ratios for all classes will be within the target range of 90% to 110%.

[11] The Domestic class increase relative to average will vary by 1.2% to ensure matching of revenue from rates to revenue requirement. The Domestic class is used to ensure matching since it is the largest class with the only revenue to cost ratio below 100% and such reconciling adjustments will have the least impact on the Domestic class.

[12] This is the proposed Rate 2.1 which effectively merges the existing Rates 2.1 and 2.2.

[13] The proposed relative rate changes by existing class for Rates 2.1 and 2.2 are:

Rate	Class	Relative to Average	*Proforma* Revenue to Cost Ratio
2.1	General Service 0-10 kW	8.0% below	104.9
2.2	General Service 10-100 kW (110 kVA)	4.9% below	108.1

[14] In other words, the proposed rates will result in the Domestic rate recovering approximately 96% of the cost of serving Domestic customers.

5.3.2 The Retail Rate Review

Newfoundland Power's Domestic and General Service rates were assessed as part of a comprehensive retail rate review (the "Retail Rate Review").[15] The objectives of the Retail Rate Review included: (i) to facilitate the exchange of information necessary to conduct a review of customer rate designs; (ii) to provide a mechanism for the participation of other interested parties in the process; and (iii) where appropriate, to recommend new rate designs for implementation. The new rate designs were to focus on providing a price signal to customers that better reflects marginal costs.[16]

The Retail Rate Review was agreed to as part of the settlement of Newfoundland Power's 2008 general rate application. The Retail Rate Review was carried out by Newfoundland Power in consultation with the Consumer Advocate, Hydro and Board staff, and consisted of a comprehensive review of existing rates and an evaluation of alternative rates.[17]

As the initial step in the Retail Rate Review in January 2009, Newfoundland Power filed a report with the Board setting out the results of its comprehensive review of its existing rates and

[15] The Retail Rate Review was provided for as part of the settlement agreement reached in respect of *Newfoundland Power's 2008 General Rate Application*. In Order No. P.U. 32 (2007), the Board observed that the proposed scope, objectives and processes will provide an open and transparent process to evaluate the designs of Newfoundland Power's rates. In Order No. P.U. 43 (2009), the Board advised the Company to file a revised schedule for the Retail Rate Review.

[16] Marginal costs are used in rate design to promote the efficient use of electricity. 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."

[17] Throughout the period from the commencement of the Retail Rate Review process in 2008, Newfoundland Power consulted with the Consumer Advocate and Hydro on an ongoing basis. In addition to numerous discussions by telephone and e-mail, there were meetings among the review participants and their respective rates experts. As the review progressed, Board staff was apprised of all material developments. Several reports were prepared and filed with the Board during the review process. Drafts of these reports were circulated to Hydro and the Consumer Advocate for comments before being finalized.

presenting certain rate design alternatives for further assessment (the “Rate Design Report”).[18]

In June 2009, Newfoundland Power filed with the Board a report summarizing customer feedback on the rate design alternatives set out in the Rate Design Report.[19] As a result of further discussions with the Consumer Advocate regarding the rate alternatives presented in the Rate Design Report, Newfoundland Power developed additional rate alternatives.[20]

In July 2010, the Consumer Advocate and Hydro, together with their rates experts, joined Newfoundland Power in a presentation of the results of the Retail Rate Review to Board staff. It was agreed at that meeting that consideration of rate structure changes that would affect standard rates should be deferred until the Company’s next general rate application,[21] but that it would be appropriate to propose implementation of an optional rate in the interim.[22]

In Order No. P.U. 8 (2011), the Board approved (i) implementation of an optional seasonal rate for Domestic customers effective July 1, 2011, and (ii) a study to evaluate time of day rates over a 2 year period (the “TOD Rate Study”).[23]

In this Application, Newfoundland Power is proposing to implement the rate structure changes arising from the Retail Rate Review that affect standard rates.

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18 The Rate Design Report gave consideration to generally accepted ratemaking principles. Specific consideration was given as to how the rate designs should reflect marginal costs and support conservation and demand management initiatives.

19 This information was obtained from customers through focus groups and a telephone survey conducted in March and April 2009. The Consumer Advocate was an observer of the customer focus group process.

20 These rate alternatives were presented in the *Illustrative Time of Use Rates* report which was filed with the Board on June 30, 2010.

21 The term “standard rates” refers to the rates generally available to all customers in a given rate class.

22 It was also agreed that Newfoundland Power, the Consumer Advocate and Hydro would provide a draft rate proposal for review by Board staff during October 2010.

23 Customer rates for the TOD Rate Study were approved in Order No. P.U. 12 (2011), concurrent with approval of the RSA and MTA adjustments effective July 1, 2011.

5.3.3 Conclusion

The customer rates proposed by Newfoundland Power in this Application reflect (i) fair allocation of costs to customers served under each of the Company's classes of service; and (ii) the rate design changes for standard rates arising from the Retail Rate Review which are being proposed to improve fairness and better reflect marginal costs.

5.4 PROPOSED RATES

The proposed customer rates in this Application were derived to provide the proposed 2013 and 2014 revenue requirements and result in an average increase in customer rates of 6.0%, effective March 1, 2013.

In addition, the customer rates proposed in this Application change structural aspects of current rates. Existing Rates 2.1 and 2.2 will be merged into a single General Service Rate for all customers with demands of less than 100 kW. Demand and energy charges are modified to better reflect marginal costs. There are also changes to energy block sizes in Rates 2.3 and 2.4; changes to basic customer charges in all rate classes; and changes to a number of other charges and rates as outlined in this section of the evidence.

5.4.1 General

Schedule 1 to the Application sets out Newfoundland Power's proposed customer rates to be effective March 1, 2013.

A report on *Customer Rate Impacts* for the Domestic and General Service classes is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 6*.

Exhibit 11, in *Volume 2, Exhibits & Supporting Materials*, provides a reconciliation of Newfoundland Power's forecast revenue from rates to the Company's revenue requirements for 2013 and 2014.

Exhibit 12, in *Volume 2, Exhibits & Supporting Materials*, provides the computation of the average increase in customer rates of 6.0% proposed by the Company.

Exhibit 13, in *Volume 2, Exhibits & Supporting Materials*, provides a comparison of Newfoundland Power's existing and proposed customer rates.[24]

5.4.2 Rate Structure Changes

Rates 2.1 and 2.2

Current Rates 2.1 and 2.2

The Company is proposing to merge Rate 2.1 and Rate 2.2 into a single rate class to address fairness of relative pricing for customers currently served under the two rate classes.[25]

Currently, Rate 2.1 applies to customers with demand requirements of less than 10 kW.[26] Rate 2.2 applies to customers with demand requirements in the range of 10 kW to 100 kW.[27] Rate 2.1

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24 The existing and proposed rates reflect the RSA and MTA factors effective July 1, 2012.

25 The detailed justification for merging Rate 2.1 and Rate 2.2 is provided in the Rate Design Report, *Section 4.1.6 Blocking Structures*, page 70-75. It is designed to eliminate the relatively large pricing differences which can result for similar electricity usage under the two current rates.

26 The approximately 12,500 customers served under Rate 2.1 comprise approximately 55% of General Service customers but account for less than 2% of overall sales. The average use for Rate 2.1 customers is slightly less than 700 kWh per year. However, the rate availability is based on demand requirements, and the energy usage of some Rate 2.1 customers can be as high as 4,000 to 5,000 kWh per month.

27 The approximately 9,000 customers served under Rate 2.2 comprise approximately 40% of Newfoundland Power's General Service customers. This class accounts for approximately 12% of total sales.

is an energy only rate; Rate 2.2 is a demand and energy rate.[28]

Many Rate 2.2 customers have similar levels of energy usage as Rate 2.1 customers. The distinguishing characteristic is typically their different demand requirements. Customers may move from Rate 2.1 to Rate 2.2, or vice versa, as a result of a very small change in demand requirements. This change in rate classification can result in a material increase or decrease in the customer's bill. Large bill increases or decreases as a result of small changes in demand usage are difficult for customers to understand and contribute to the misperception that a rate which includes a demand charge is inevitably more costly for customers than an energy only rate.

Proposed Merged Rate 2.1

The merged Rate 2.1 will consist of a basic customer charge, a higher-priced energy charge for the first 3,500 kWh of consumption, a lower-priced energy charge for consumption above 3,500 kWh and a demand charge for demand in excess of 10 kW. The Maximum Monthly Charge, which limits the unit cost on a per kWh basis, will continue to apply.

The provision of an initial block of demand to which no demand charge applies ensures smooth transition from an energy only rate to a demand and energy rate upon a customer exceeding 10 kW of demand. This is a common rate design approach among electric utilities in Canada.[29]

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[28] A rate design with separate charges for demand and energy use is a common rate design. It provides a price signal to encourage customers to manage both their demand and energy use.

[29] Canadian electric utilities that provide an initial demand block for which no demand charges apply include SaskPower, Manitoba Hydro, Maritime Electric, NB Power, Hydro Quebec and BC Hydro.

The revenue to cost ratios for each of Rate 2.1 and Rate 2.2 are currently higher than 113%. It is proposed that the average rate change for the merged Rate 2.1 be set to bring the class revenue to cost ratio within the 90% to 110% target range.[30] Implementing the proposed new rate structure is forecast to reduce the revenue to cost ratio for the merged rate class to 107.6%.

The overall impact of these changes is a class revenue increase of 0.6% for the proposed merged Rate 2.1.[31]

Rate 2.3

The Company is proposing to increase the upper limit of the first energy block from 30,000 kWh per month to 50,000 kWh per month to provide for a better balance of cost recovery among customers with different demand requirements. The assessment of the current rate structure indicated a higher cost recovery for customers with low demand requirements and a lower cost recovery for customers with high demand requirements. The proposed higher upper limit of 50,000 kWh will reduce cost recovery differences among customers with different demand requirements.[32]

Rate 2.4

The Company is proposing a reduction in the first block size from 100,000 kWh per month to 75,000 kWh per month to provide a smooth price transition for customers that move between Rate 2.3 and Rate 2.4.[33]

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[30] Reducing the class revenue to a revenue to cost ratio of between 90% to 110% also serves to mitigate customer bill impacts which would otherwise arise as a result of merging Rate 2.1 and Rate 2.2.

[31] The customer impact of the proposed merged rate for the existing Rate 2.1 class is a 2.0% *decrease*. The customer impact of the proposed merged rate for the existing Rate 2.2 class is a 1.1% *increase*.

[32] The justification for the increase in the size of the first block of kWh for Rate 2.3 is provided in the Rate Design Report, *Section 4.1.6 Blocking Structures*, page 75-78.

[33] The justification for the decrease in the size of the first block of kWh for Rate 2.4 is provided in the Rate Design Report, *Section 4.1.6 Blocking Structures*, page 78-80.

5.4.3 Basic Customer Charges

Rate 1.1

The Company is proposing to implement a separate basic customer charge in Rate 1.1 for customers requiring an electrical service in excess of 200 Amps. This is to reflect the higher cost of providing >200 Amp service.[34]

There are approximately 1,750 Domestic customers that have >200 Amp services. The proposed initial increase in the basic customer charge for these customers is $5 per month.[35]

The Company is proposing no change in the standard basic customer charge (i.e., for those with ≤200 Amp services). This will allow for a higher increase in the energy charge which, in turn, will better reflect marginal energy costs.[36]

Proposed Merged Rate 2.1

The basic customer charge for the merged Rate 2.1 is proposed to increase to $22.25. For the Rate 2.1 class, the increased basic customer charge provides an improved recovery of customer costs in a class with very low average usage. The customer impact of the increased basic customer charge for Rate 2.1 customers will be offset by a reduction in the energy charge.[37]

The assessment of customer costs for the proposed Rate 2.1 customers indicates different basic customer charges can be justified for customers with unmetered services, single phase services

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34 The justification for the higher customer charge for >200 Amp service is provided in the Rate Design Report, Section 3.1.2 *Basic Customer Charge*, page 25.

35 To limit the customer impact, it is proposed that the full average customer cost difference associated with >200 Amp service not be reflected in the basic customer charge at this time.

36 See discussion of Domestic energy charge in *Section 5.4.4 Demand and Energy Charges* on page 5-16.

37 Approximately 46% of existing Rate 2.1 customers will receive decreases under the proposed rate; the maximum increase for any existing Rate 2.1 customer is less than $5.00 per month.

and three phase services.[38] The Company is proposing to defer the introduction of a separate customer charge for three-phase service and unmetered services until the next general rate application. This approach will limit the immediate customer impacts resulting from the merging of the current Rate 2.1 and Rate 2.2.

A minimum monthly charge currently applies to customers that require three phase service.[39] The three phase minimum monthly charge has historically been set to equal two times the basic customer charge for Rate 2.1. The Company is proposing no change in the minimum monthly charge until such time as separate single phase and three phase basic customer charges are introduced.[40]

Rates 2.3 and 2.4

The Company is proposing to reduce the basic customer charges for Rate 2.3 and Rate 2.4 to exclude the effect of the cost of metering tanks.[41] Most Rate 2.3 and 2.4 customers do not require metering tanks. New customers that do require metering tanks are required by the Company's current contribution policy to pay the incremental cost.[42] From a rate design perspective, it is appropriate to exclude the customer cost effects of metering tanks in determining the basic customer charges for Rate 2.3 and Rate 2.4.

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[38] The justification for the introduction of separate customer charges is provided in the Rate Design Report, Section 4.1.2 *Basic Customer Charges*, page 60-62.

[39] The minimum three phase charge is currently $35.98. This charge applies to three phase customers on Rate 2.1 and Rate 2.2 when the total of the other charges is computed to be less than $35.98.

[40] In the absence of a separate minimum monthly charge, the basic customer charge effectively serves as a minimum monthly charge. To avoid undue confusion, it is proposed to leave the current minimum monthly charge for three phase service unchanged until the next general rate application, at which time it is anticipated it will be replaced by a new separate basic customer charge for three phase service.

[41] The justification for the reduction of the basic customer charges for Rate 2.3 and Rate 2.4 is provided in the Rate Design Report, *Section 4.1.2 Basic Customer Charges*, page 63.

[42] Based on the differential between the cost of the metering tank and the cost of secondary metering.

5.4.4 Demand and Energy Charges

Domestic

The Company is proposing to increase the Rate 1.1 energy charge by 7.9%. This increase is approximately 0.7% higher than the average increase for the Domestic class. The purpose of directing a greater proportion of the Domestic class increase to the energy charge is to better reflect marginal energy costs.

General Service

The Company is proposing to increase the demand price differential between winter and non-winter periods from $1.50 to $2.50 per kW/kVA to better reflect seasonal differences in marginal capacity costs.[43]

5.4.5 Other Charges

Maximum Monthly Charge

The Company is proposing to change the Rate Stabilization Clause so that the Maximum Monthly Charge will be updated annually to reflect changes in the Rate Stabilization Adjustment Factor. This approach will provide a more reasonable recovery of changing fuel costs between test years from customers that benefit from the Maximum Monthly Charge.[44]

The current Rate Stabilization Adjustment Factor is 1.770¢ per kWh. Implementation of this proposal with the current Rate Stabilization Adjustment increases the Maximum Monthly Charge

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[43] The justification for the increase in the seasonal demand charge differential and the reduction of demand charges offset by an increase in energy charges is provided in the Rate Design Report, *Sections 4.1.3 Demand Charges*, page 64 and *Section 4.1.4 Energy Charges*, page 65.

[44] The justification for eliminating the exemption from the RSA Factor for the Maximum Monthly Charge is provided in the Rate Design Report, *Section 4.1.5 Maximum Monthly Charge*, page 66-70.

by 10.9%.[45] To limit the customer impacts, the Company is proposing that the change to the Rate Stabilization Clause be approved to become effective at the time Hydro's next base rate increase is flowed through to Newfoundland Power.[46]

In this Application, the energy charge portion of the Maximum Monthly Charge is proposed to increase by the average overall increase.

Curtailable Service Option

It is proposed that the availability of the Curtailable Service Option for General Service customers be maintained, and that the current credit of $29 per kVA remain unchanged.[47]

Early Payment Discount

The Company is proposing to modify the provision for an early payment discount so that all customers receive the same 1.5% discount.[48] This requires the elimination of the $1 minimum monthly discount for Rates 1.1, 2.1 and 2.2 and the elimination of the $500 maximum monthly discount for Rates 2.3 and 2.4. The current minimum discount provides a high percentage discount for customers with very low usage and the maximum discount provides a very low percentage discount for customers with very high usage. Providing all customers with the same early payment discount on a percentage basis is a fairer approach.

[45] 1.770¢ per kWh is the largest Rate Stabilization Adjustment since the Rate Stabilization Clause was created in 1985.

[46] The current Rate Stabilization Adjustment of 1.770¢ per kWh reflects a fuel rider of 2.056¢ per kWh. At the time of a Hydro base rate change, there normally is no fuel rider in effect. As a result, the customer impact of implementation will be much less.

[47] The justification for maintaining the Curtailable Service Option is provided in the Rate Design Report, *Section 4.1.8 Curtailable Service Option*, page 81-83.

[48] The justification for the change in the application of the early payment discount is provided in the Rate Design Report, *Section 3.1.4*, page 28-29 and *Section 4.1.7*, page 81.

5.4.6 Optional Seasonal Rate and TOD Rate Study

In Order No. P.U. 8 (2011), the Board approved the implementation of the Rate 1.1S Domestic Seasonal Optional rate ("Optional Seasonal Rate") and the Time of Day ("TOD") Rate Study. The Board also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for deferral of the annual costs and revenue effects of the Optional Seasonal Rate and the annual operating costs associated with of the TOD Rate Study.[49]

The Company is proposing to maintain the Optional Seasonal Rate Revenue and Cost Recovery Account until its next general rate application. By then, the TOD Rate Study will be completed and it is expected that the number of customers participating in the Optional Seasonal Rate will be reasonably predictable.[50]

The Optional Seasonal Rate is proposed to be increased by 7.2%.[51] The TOD Rates are proposed to be increased by the same amount as the relevant rate class with which the rate is associated.[52]

5.5 SUPPLY COST MECHANISMS

This section of the evidence outlines the results of Newfoundland Power's review of its supply cost mechanisms required by Order No. P.U. 43 (2009).

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[49] For the 6 months the Optional Seasonal Rate was in effect in 2011, the revenue impact was $70,090 and the operating cost effect was $71,364. The TOD Rate Study is still in its first year of operation; the rates went into effect in December 2011. During 2011, the operating costs associated with the TOD Rate Study were $186,552.

[50] There are currently approximately 1,700 Domestic customers on the Optional Seasonal Rate. The Company will continue to promote this optional rate through articles in the Power Connections newsletter and via messages on the monthly bills of customers whose usage history indicates the rate would be beneficial to them.

[51] This is consistent with the proposed increase in Rate 1.1.

[52] For the Domestic TOD rate, the average increase in the energy charges equals the percent increase applied to the Domestic energy rate. For the Rate 2.4 TOD rate, all charges reflect the class average increase.

By Order No. P.U. 43 (2009), Newfoundland Power was required to examine the incentive effects of its regulatory mechanisms and consider the effectiveness and efficiency of the incentive to reduce purchased power costs.

A report on the Company's review of Supply Cost Mechanisms is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 7.*

As a result of its review of supply cost mechanisms, Newfoundland Power has concluded that:

1. current mechanisms which provide for recovery of prudently incurred supply costs remain consistent with sound public utility practice and current Canadian regulatory practice;

2. current mechanisms provide reasonable incentives for the Company to further customer conservation of demand and energy; and

3. future recovery of Weather Normalization Reserve transfers through the RSA would provide an increased measure of regulatory consistency and continued rate stability.[53]

5.6 RATE STABILIZATION CLAUSE

This section of the evidence outlines proposed changes to the Rate Stabilization Clause to (i) permit the Maximum Monthly Charge in proposed Rate 2.1 and existing Rates 2.3 and 2.4 to reflect annual changes in the Rate Stabilization Adjustment Factor; (ii) reflect the most recent

[53] *Section 5.6.1 Proposed Changes* provides the Company's proposed approach to disposition of transfers to the Weather Normalization Reserve.

energy consumption information for street and area lighting fixtures; (iii) permit recovery of customer energy conservation program costs through the RSA; and (iv) permit recovery of annual transfers to the Weather Normalization Reserve through the RSA.

5.6.1 Proposed Changes

Maximum Monthly Charge

The Maximum Monthly Charge provided for in Rates 2.2, 2.3 and 2.4 is currently exempt from changes in the RSA Factor implemented in the annual July 1st customer rate adjustment. In this Application, the Company is proposing to eliminate this exemption, effective at the time of Hydro's next base rate flow-through to Newfoundland Power.[54]

Exhibit 14, page 1 of 4, in *Volume 2, Exhibits & Supporting Materials*, provides the existing and proposed wording of Section III of the Rate Stabilization Clause necessary to effect this change.

Street and Area Lighting

Section II (3) of the Rate Stabilization Clause provides the annual kWh used in calculating the Rate Stabilization Adjustment for the street and area lighting rates.

Exhibit 14, page 2 of 4, in *Volume 2, Exhibits & Supporting Materials*, provides a revised Section II (3) of the Rate Stabilization Clause, which provides the updated energy consumption information for the Company's street and area lighting fixtures.[55]

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[54] See *Section 5.4.5 Other Charges*, page 5-16.

[55] This reflects updated fixture ballast information provided by the suppliers of the lighting fixtures.

Conservation Program Cost Recovery

In this Application, Newfoundland Power is proposing to amortize the recovery of customer energy conservation program costs over a 7 year period and to recover those costs through the RSA. Program costs incurred in each year are proposed to be recovered through the RSA over a fixed amortization period of 7 years, such period to commence in the year following the year in which the costs are incurred.[56]

Exhibit 14, page 3 of 4, in *Volume 2, Exhibits & Supporting Materials*, provides the proposed change to the Rate Stabilization Clause to provide for recovery of customer energy conservation program costs charged to the Conservation and Demand Management Cost Deferral Account.[57]

Weather Normalization Reserve Balance Disposition

In this Application, the Company is proposing that annual year end balances in the Weather Normalization Reserve be recovered from, or credited to, customers as part of the Company's annual RSA adjustment to customer rates on July 1st of each year.[58]

Exhibit 14, page 4 of 4, in *Volume 2, Exhibits & Supporting Materials*, provides the proposed change to the Rate Stabilization Clause to enable the ongoing disposition of the annual transfers to the Weather Normalization Reserve.

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56 See *Section 2.2.2 Conservation Programming* and *Section 3.4.3 Conservation Program Costs*.

57 A proposed definition of the *Conservation and Demand Management Cost Deferral Account* is contained in *Volume 2, Exhibits & Supporting Materials, Exhibit 7*.

58 See *Section 3.4.4 Weather Normalization Reserve*.