NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

October 16, 2015

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: 2016/2017 General Rate Application

1. Background

In Order No. P.U. 13 (2013), the Board ordered, amongst other things, that Newfoundland Power Inc. ("Newfoundland Power" or the "Company") file its next general rate application with a 2016 test year on or before June 1, 2015 unless otherwise directed by the Board. This general rate application was to include (i) a report in relation to Newfoundland Power's capital structure and (ii) a depreciation study relating to plant in service as of December 31, 2014.

In Order No. P.U. 15 (2015), the Board ordered that Newfoundland Power file its next general rate application with a 2016 test year on or before October 16, 2015.

The filing forwarded with this letter complies with the Board's orders.

2. The Filing

Enclosed with this letter are the original and 11 copies of a general rate application for a review of Newfoundland Power's 2016 and 2017 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 (i) the expert cost of capital evidence of Mr. James Coyne of Concentric Energy Advisors, which includes a report in relation to Newfoundland Power's capital structure and (ii) a Depreciation Study based upon plant in service at December 31, 2014 prepared by Mr. John Wiedmayer of Gannett Fleming Valuation and Rate Consultants, LLC.*

3. Application Proposals

General

The Application proposes that the Board approve an overall average increase in Newfoundland Power's current customer rates of approximately 3.1%, with effect from July 1, 2016.

The 3.1% proposed overall average increase in rates is primarily the result of 3 changes in Newfoundland Power's cost of service. Approximately 1.4% results from a mixture of cost changes ranging from increased operating expenses to the cost of increased utility investment. Rebalancing 2016 and 2017 supply costs from Newfoundland and Labrador Hydro ("Hydro") accounts for approximately 0.9% of the proposed increase. Finally, increasing Newfoundland Power's ratemaking return on equity for 2016 and 2017 accounts for approximately 0.8% of the increase.

Cost of Capital

The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2016 and 2017 is 9.5% based upon a 45% common equity ratio. Further, the automatic adjustment formula used prior to 2013 to annually establish the Company's cost of equity (the "Formula") should not be reinstated under current financial market conditions.

Regulatory Accounting

The Application proposes that, commencing in 2016, Newfoundland Power:

1. implement new depreciation rates and amortize an accumulated reserve variance based on the 2014 Depreciation Study filed with the Application; and

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2. amortize over the 2016 to 2018 period:
    a) an estimated $1.2 million in Consumer Advocate and Board hearing costs associated with the Application; and
    b) a 2016 revenue shortfall of approximately $4.1 million resulting from a forecast July 1, 2016 implementation of the proposed customer rate changes.

Customer Rates
The rate proposals in the Application reflect the Company's most recent cost of service study.

The rates, tolls and charges proposed in the Application will result in an average overall rate increase of 3.1%. The increases in proposed customer rates by class are as follows:

Rate Class	***Average Increase***
Domestic	3.6%
General Service 0-100 kW (110 kVA)	3.1%
General Service 110-1000 kVA	0.6%
General Service 1000 kVA and Over	3.1%
Street and Area Lighting	3.1%

The higher proposed increase for Domestic customers and the lower proposed increase for General Service 110-1000 kVA customers are required to maintain revenue to cost ratios for all customer classes within the range of 90% to 110%. Changes to the Basic Customer Charge for Rate 2.1 to introduce different customer charges for (i) unmetered service, (ii) single-phase service, and (iii) three-phase service are also proposed.

4. Process & Related Matters

Newfoundland Power would be grateful if the Board would (i) give public notice of the Application, (ii) call of a pre-hearing conference, and (iii) establish a schedule for the Application at its earliest convenient opportunity. This will permit the Application to be processed in a transparent and efficient manner consistent with the establishment of customer rates on July 1, 2016.

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, QC
Vice President,
Regulation & Planning

Enclosures

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

Thomas Johnson (3 copies)
Messrs. O'Dea Earle
Consumer Advocate

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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 2016 and 2017.

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

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

A. Background:

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

2. The Act provides that the Board has the general supervision of public utilities and requires, 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. In Order No. P.U. 7 (1996-1997), the Board, amongst other things, directed Newfoundland Power to evaluate customer conservation programs by use of the total resource cost test and the rate impact measure.

4. By Order No. P.U. 13 (2013), the Board, amongst other things, ordered Newfoundland Power to file its next general rate application no later than June 1, 2015 with a 2016 test year unless otherwise ordered by the Board. In Order No. P.U. 15 (2015), the Board ordered the Company to file its next general rate application by October 16, 2015 with a 2016 test year.

5. In Order No. P.U. 13 (2013), the Board, amongst other things, ordered Newfoundland Power to file (i) a depreciation study based upon plant in service as at December 31, 2014; and (ii) a report on Newfoundland Power's capital structure, with its next general rate application.

6. The Application complies with the Orders of the Board as described in paragraphs 4 and 5 hereof.

B. Newfoundland Power Proposals:

7. Newfoundland Power proposes that the Board approve the Company's evaluation of customer conservation programs by the use of the total resource cost test and program administrator cost test as described in the evidence filed in support of the Application.

8. Newfoundland Power proposes that the Board continue to refrain from the use of an automatic adjustment formula for setting the allowed rate of return on rate base for Newfoundland Power, in years subsequent to 2017, for the reasons set out in the evidence filed in support of the Application.

9. Newfoundland Power proposes that the Board approve the calculation of depreciation expense with effect from January 1, 2016 by use of the depreciation rates as recommended in the Depreciation Study filed with the Application, which rates include the recovery in depreciation expense over the remaining life of the assets of an accumulated reserve variance identified in the Depreciation Study.

10. Newfoundland Power proposes that the Board approve amortizations, for the period 2016 through 2018, to:

    (a) amortize the recovery over a three year period of an estimated $1,200,000 in Board and Consumer Advocate costs related to the Application; and

    (b) amortize the recovery over a three year period of a forecast 2016 revenue shortfall of an estimated $4,095,000;

    as more fully described in the evidence filed in support of the Application.

11. Newfoundland Power proposes that the Board approve an overall average increase in current customer rates of 3.1%, with effect from July 1, 2016, based upon:

    (a) a forecast average rate base for 2016 of $1,060,331,000 and for 2017 of $1,105,064,000;

    (b) a rate of return on average rate base for 2016 of 7.66% in a range of 7.48% to 7.84% and for 2017 of 7.64% in a range of 7.46% to 7.82%; and

    (c) forecast revenue requirements from customer rates for 2016 of $669,685,000 and for 2017 of $682,578,000;

    as more fully described in the evidence filed in support of the Application.

12. Newfoundland Power proposes that the Board approve (i) rates, tolls and charges, as set out in Schedule A to the Application, and (ii) rules and regulations governing service, as set out in Schedule B to the Application, which result in average increases in proposed customer rates by class as follows:

Rate Class	***Average Increase***
Domestic	3.6%
General Service 0-100 kW (110 kVA)	3.1%
General Service 110-1000 kVA	0.6%
General Service 1000 kVA and Over	3.1%
Street and Area Lighting	3.1%

all to be effective for service provided, on and after July 1, 2016 as more fully described in the evidence filed in support of the Application.

13. Newfoundland Power proposes that the Board approve changes to the General Service contribution in aid of construction policy to be effective on and after July 1, 2016 to appropriately reflect the proposed changes described in paragraph 12 of the Application.

C. Order Requested:

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

(a) the evaluation of customer energy conservation programs by use of the total resource cost test and program administrator cost test as set out in paragraph 7 of the Application;

(b) pursuant to Section 80 of the Act, the continued discontinuation of use of an automatic adjustment formula as set out in paragraph 8 of the Application;

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

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

(e) pursuant to Sections 70 and 80 of the Act:

(i) rates, tolls and charges as set out in Schedule A to the Application;
(ii) rules and regulations governing service as set out in Schedule B to the Application; and
(iii) changes to the General Service contribution in aid of construction policy;

all of which reflect paragraphs 11, 12 and 13 of the Application, to be effective for service provided on or after July 1, 2016; and

(f) such further or other matters that appears just and reasonable on the evidence.

D. Communications:

15. Communication with respect to this Application should be forwarded to the attention of Ian F. Kelly, and Peter Alteen, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland, this 16th day of October, 2015.

NEWFOUNDLAND POWER INC.

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

IN THE MATTER OF a general rate application (the "Application") by Newfoundland Power Inc. ("Newfoundland Power") to establish customer electricity rates for 2016 and 2017.

AFFIDAVIT

I, Gary Smith, of St. John's in the Province of Newfoundland and Labrador, Professional Engineer, make oath and say as follows:

1. That I am President and Chief Executive Officer 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 16th day of October, 2015,
before me:

Barrister	Gary Smith

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 .... $16.26 per month
Exceeding 200 Amp Service .... $21.26 per month

Energy Charge:
All kilowatt-hours .... @10.959¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service .... $16.26 per month
Exceeding 200 Amp Service .... $21.26 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:

Unmetered .... $17.65 per month
Single Phase .... $21.65 per month
Three Phase .... $27.65 per month

Demand Charge:
$9.34 per kW of billing demand in the months of December, January, February and March and $6.84 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 .... @ 10.861¢ per kWh
All excess kilowatt-hours .... @ 8.033¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.345 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

Unmetered .... $17.65 per month
Single Phase .... $21.65 per month
Three Phase .... $33.65 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: .... $50.41 per month

Demand Charge:
$7.88 per kVA of billing demand in the months of December, January, February and March and $5.38 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 .... @ 9.213¢ per kWh
All excess kilowatt-hours .... @ 7.329¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.345 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: .... $87.71 per month

Demand Charge:
$7.57 per kVA of billing demand in the months of December, January, February and March and $5.07 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 .... @ 8.870¢ per kWh
All excess kilowatt-hours .... @ 7.258¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.345 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)	$17.38	$18.80
150W (14,400 lumens)	21.36	-
250W (23,200 lumens)	29.51	-
400W (45,000 lumens)	40.36	-

Special poles used exclusively for lighting service**	
Wood	$6.59
30' Concrete or Metal, direct buried	9.43
45' Concrete or Metal, direct buried	15.46
25' Concrete or Metal, Post Top, direct buried	7.01
Underground Wiring (per run)**	
All sizes and types of fixtures	$16.05

** 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"), whether individually or in aggregate, 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.

Customers that reduce their demand in aggregate will be treated as a single Customer under this rate option. The aggregated Customer must provide a single point of contact for a request to Curtail.

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 for failure to Curtail in a winter period as follows:

1. For the first 5 curtailment requests the Curtailment Credit will be reduced 25% for each failure to Curtail.

2. After the 5th curtailment 50% of the remaining Curtailment Credit, if any, will become vested (“Vested Curtailment Credit”).

3. For all remaining curtailment requests the Curtailment Credit will be reduced by 12.5% for each additional failure to Curtail.

If a Customer fails to Curtail four times during a winter period, then:

1. The Customer shall only be entitled to the Vested Curtailable Credit, if any.

2. The Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraphs, 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.
RULES AND REGULATIONS

1. INTERPRETATION:

(a) In these Rates, Rules and Regulations the following definitions shall apply:

(i) "Act" means The Public Utilities Act RSN 1970 c. 322 as amended from time to time.
(ii) "Applicant" means any person who applies for Service.
(iii) "Board" means the Board of Commissioners of Public Utilities of Newfoundland and Labrador.
(iv) "Company" means Newfoundland Power Inc.
(v) "Customer" means any person who accepts or agrees to accept Service.
(vi) "Disconnected" or "Disconnect" in reference to a Service means the physical interruption of the supply of electricity thereto.
(vii) "Discontinued" or "Discontinue" in reference to a Service means to terminate the Customer's on-going responsibility with respect to the Service.
(viii) "Domestic Unit" means a house, apartment or other similar residential unit which is normally occupied by one family, or by a family and no more than four other persons who are not members of that family, or which is normally occupied by no more than six unrelated persons.
(ix) "Service" means any service(s) provided by the Company pursuant to these Regulations.
(x) "Serviced Premises" means the premises at which Service is delivered to the Customer.

(b) Unless the context requires otherwise these Rates, Rules and Regulations shall be interpreted such that

(i) words imparting male persons include female persons and corporations.

(ii) words imparting the singular include the plural and vice versa.

2. CLASSES OF SERVICE:

(a) The Company shall provide the following classes of Service:

(i) Domestic Service
(ii) General Service, 0-100 kW (110 kVA)
(iii) General Service, 110 kVA (100 kW) - 1000 kVA
(iv) General Service, 1000 kVA and Over
(v) Street and Area Lighting Service

(b) The terms and conditions relating to each class of Service shall be those approved by the Board from time to time.

(c) Service, other than Street and Area Lighting Service, shall be metered except where the energy consumption is relatively low and constant and, in the opinion of the Company, can be readily determined without metering.

(d) The Customer shall use the Service on the Serviced Premises only. The Customer shall not resell the Service in whole or in part, except that the Customer may include the cost of Service in charges for the lease of space, or as part of the cost of other services provided by the Customer.

3. APPLICATION FOR SERVICE:

(a) An Applicant, when required by the Company, shall complete a written Electrical Service Contract.

(b) An application for Service, when accepted by the Company, constitutes a binding contract between the Applicant and the Company which cannot be assigned.

(c) The person who signs an application for Service shall be personally liable for Service provided pursuant thereto, unless that person has authority to act for another person denoted as the Applicant on the application for Service.

(d) The Company may in its discretion refuse to provide Service to an Applicant where:

(i) the Applicant fails or refuses to complete an application for Service.

(ii) the Applicant provides false or misleading information on the application for Service.

(iii) the Applicant or the owner or an occupant of the Serviced Premises has a bill for any Service which is not paid in full 30 days or more after issuance.

(iv) the Applicant fails to provide the security or guarantee required under Regulation 4.

(v) the Applicant is not the owner or an occupant of the Serviced Premises.

(vi) the Service requested is already supplied to the Serviced Premises for another Customer who does not consent to having his Service Discontinued.

(vii) the Applicant does not pay a charge described in Regulation 9 (b), (c), or (d).

NEWFOUNDLAND POWER INC.
RULES AND REGULATIONS

(viii) the Applicant otherwise fails to comply with these Regulations.

(e) A Customer who has not completed an application for Service shall do so within 5 days of a request having been made by the Company in writing.

4. SECURITY FOR PAYMENT:

(a) An Applicant or a Customer shall give such reasonable security for the payment of charges as may be required by the Company pursuant to its Customer Deposit Policy as approved by the Board, from time to time.

(b) The Company may in its discretion require special guarantees from an Applicant or Customer whose location or load characteristics would require abnormal investment in facilities or who requires Service of a special nature.

5. SERVICE STANDARDS - METERED SERVICES:

(a) Service shall normally be provided at one of the following nominal standard secondary voltages depending upon the requirements of the load to be served and the availability of a three-phase supply:

Single-phase, 3 wire, 120/240 volts
Three-phase, 4 wire, 120/208 volts wye
Three-phase, 4 wire, 347/600 volts wye

Service at any other supply voltage may be provided in special cases at the discretion of the Company.

(b) Service to customers who are provided Domestic Service shall be supplied at single phase 120/240 volts or as part of a multiunit building, at single phase 120/208 volts. The Company may, if requested by the customer, provide three phase service if a contribution in aid of construction is paid to the Company in accordance with Regulation 9(c).

(c) The Company shall not be required to provide services at 50 hertz except to those Serviced Premises receiving 50 hertz power continuously since May 13, 1977.

(d) The Company shall determine the point at which power and energy is delivered from the Company's facilities to the Customer's electrical system.

(e) Service entrances shall be in a location satisfactory to the Company and, except as otherwise approved by the Company, shall be wired for outdoor meters.

(f) Where the Company has reason to believe that Service to a Customer has or will have load characteristics which may cause undue interference with Service to another Customer, the Customer shall upon written notice by the Company provide and install, at his expense and within a reasonable period of time, the equipment necessary to eliminate or prevent such interference.

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(g) (i) Any Customer having a connected load or a normal operating demand of more than 25 kilowatts, in areas served by underground wiring or where space limitations or aesthetic reasons make it impractical to use a pole mounted transformer bank or pad transformer, shall, on request of the Company, provide at its expense a suitable vault or enclosure on the Serviced Premises for exclusive use by the Company for its equipment necessary to supply and maintain service to the Customer.

(ii) Where either the service requirements of a Customer or changes to a Customer's electrical system necessitate the installation of additional equipment to the Company's system which cannot be accommodated in the Company's existing vaults or structures, the Customer shall, on request of the Company, provide at the Customer's expense such additional space in its vault or enclosure as the Company shall require to accommodate the additional equipment.

(h) The Customer shall not use a Service for across the line starting of motors rated over 10 horsepower, except where specifically approved by the Company.

(i) For Services having rates based on kilowatt demand, the average power factor shall not be less than 90%. The Company, in its discretion, may make continuous tests of power factor or may test the Customer's power factor from time to time. If the Customer's power factor is lower than 90%, the Customer shall upon written notice by the Company provide, at his expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

(j) The Company shall provide transformation for Service up to 500 kVA where the required service voltage is one of the Company's standard service voltages and installation is in accordance with the Company's standards. In other circumstances, the Company, on such conditions as it deems acceptable, may provide the transformation.

(k) All Customer wiring and installations shall be in compliance with all statutory and regulatory requirements including the Canadian Electrical Code, Part 1, and, where applicable, in accordance with the Company's specifications. However, the provision of Service shall not in any way be construed as acceptance by the Company of the Customer's electrical system.

(l) The Customer shall provide such protective devices as may be necessary to protect his property and equipment from any disturbance beyond the reasonable control of the Company.

6. SERVICE STANDARDS - STREET AND AREA LIGHTING SERVICE:

(a) For Street and Area Lighting Service the Company shall use its best efforts to provide illumination during the hours of darkness for a total of approximately 4200 hours per year. The Company shall, subject to Regulation 9 (i) make all repairs necessary to maintain service.

(b) The Company shall supply the energy required and shall provide and maintain the illuminating fixtures and lamps together with necessary overhead or underground conductors, control equipment and other devices.

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(c) The Company shall not be required to provide Street And Area Lighting Service where, in the opinion of the Company, the normal Service is unsuitable for the task or where the nature of the activities carried out in the area would likely result in damage to the poles, wiring or fixtures.

(d) The Company shall provide a range of fixture sizes utilizing an efficient lighting source in accordance with current standards in the industry and shall consult with the Customer regarding the most appropriate use of such fixtures for any specific installation.

(e) The location of fixtures for Street and Area Lighting Service shall be determined by the Company in consultation with the Customer. After poles and fixtures have been installed they shall not be relocated except at the expense of the Customer.

(f) The Company does not guarantee that fixtures used for Street And Area Lighting Service will illuminate any specific area.

(g) The Company shall not be required to provide additional Street And Area Lighting Service to a Customer where on at least two occasions in the preceding twelve months, his bill for such Service has been in arrears for more than 30 days.

7. METERING:

(a) Service to each building shall be metered separately except as provided in Regulation 7(b).

(b) Service to buildings and facilities on the same Serviced Premises which are occupied by the same Customer may, subject to Regulation 7(c), be metered together provided the Customer supplies and maintains all distribution facilities beyond the point of supply.

(c) Except as provided in Regulation 7(d), Service to each new Domestic Unit shall be metered separately.

(d) Where an existing Domestic Unit is subdivided into two or more new Domestic Units, Service to the new Domestic Units may, in the discretion of the Company, be metered together.

(e) Where four or more Domestic Units are metered together, the Basic Customer Charge shall be multiplied by the number of Domestic Units.

(f) Where the Service to a Domestic Unit has a connected load for commercial or non-domestic purposes exceeding 3000 watts, exclusive of space heating, the Service shall not qualify for the Domestic Service Rate.

(g) The Company shall not be required to provide more than one meter per Service, however submetering by the Customer for any purpose not inconsistent with these Regulations, is permitted.

(h) Subject to Regulations 7(c) and 7(g) Service to different units of a building may, at the request of the Customer, be combined on one meter or be metered separately.

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(i) Maximum demand for billing purposes shall be determined by demand meter or, at the option of the Company, may be based on:

(i) 80% of the connected load, where the demand does not exceed 100 kW, or

(ii) the smallest size transformer(s) required to serve the load if it is intermittent in nature such as X-Ray, welding machines or motors that operate for periods of less than thirty minutes, or

(iii) the kilowatt-hour consumption divided by an appropriate number of hours use where demand is less than 10 kW.

(j) When charges are based on maximum demand the metering shall normally be in kVA if the applicable rate is in kVA and in kW if the applicable rate is in kW.

If the demand is recorded on a kVA meter but the applicable rate is based on a kW demand, the recorded demand may be decreased by ten percent (10%) and the result shall be treated as the kW demand for billing purposes.

If the demand is recorded on a kW meter but the applicable rate is based on a kVA demand, the recorded demand may be increased by ten percent (10%) and the result shall be treated as the kVA demand for billing purposes.

(k) The Customer shall ensure that meters and related equipment are visible and readily accessible to the Company's personnel and are suitably protected. Unless otherwise approved by the Company, meters shall be located outdoors and shall not subsequently be enclosed.

(l) If a meter is located indoors and Company employees are unable to obtain access to read the meter at the normal reading time for three consecutive months, the Customer shall upon written notice given by the Company, provide for the installation of an outdoor meter at his expense.

(m) In the event that a dispute arises regarding the accuracy of a meter, and the Company is unable to resolve the matter with the Customer then either the Customer or the Company shall have the right to request an accuracy test in accordance with the requirements of the Electricity Inspection Act of Canada. Should the test indicate that the meter accuracy is not within the allowable limits, the Customer's bill shall be adjusted in accordance with the provisions of the said Act and all costs involved in the removal and testing of the meter shall be borne by the Company. Should the test confirm the accuracy of the meter, the costs involved shall be borne by the party requesting the test. The Company may require a Customer to deposit with the Company in advance of testing, an amount sufficient to cover the costs involved.

(n) Metering shall normally be at secondary distribution voltage level but may at the option of the Company be at the primary distribution level. When metering is at the primary distribution voltage (4 - 25 kV) the monthly demand and energy consumption shall be reduced by 1.5%.

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8. METER READING:

(a) Where reasonably possible the Company shall read meters monthly provided that the Company may, at its discretion, read meters at some other interval and estimate the reading for the intervening month(s). Areas which consist primarily of cottages will have their meters read four times per year and the Company will estimate the readings for all other months.

(b) If the Company is unable to obtain a meter reading due to circumstances beyond its reasonable control, the Company may estimate the reading.

(c) If due to any cause a meter has not correctly recorded energy consumption or demand, then the probable consumption or demand shall be estimated in accordance with the best data available and used to determine the relevant charge.

9. CHARGES:

(a) Every Customer shall pay the Company the charges approved by the Board from time to time for the Service(s) provided to the Customer or provided to the Serviced Premises at the Customer's request.

(b) Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay the Company a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material. The payment may be required in advance or, subject to credit approval, billed to the Customer.

(c) Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay the Company the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment. The payment may be required in advance or, subject to credit approval, billed to the Customer.

(d) The Customer shall pay the Company in advance or on such other terms approved by the Board from time to time any contribution in aid of construction as may be determined by the methods prescribed by the Board.

(e) The Customer shall pay the Company the amount set forth in the rate for all poles required for Street and Area Lighting Service which are in addition to those installed by the Company for the distribution of electricity. This charge shall not apply to Company poles and communications poles used jointly for Street and Area Lighting Service and communications attachments.

(f) Where a Service is Disconnected pursuant to Regulation 12(a), b(ii), (c) or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee.

Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee.

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The reconnection fee shall be $20.00 where the reconnection is done during normal office hours or $40.00 if it is done at other times.

(g) Where a Service, other than a Street and Area Lighting Service, is Discontinued pursuant to Regulation 11(a), or Disconnected pursuant to Regulations 12(a), b(ii), (c) or (d) and the Customer subsequently requests that the Service be restored within 12 months, the Customer shall pay, in advance, the minimum monthly charges that would have been incurred over the period if the Service had not been Discontinued or Disconnected.

(h) (i) Where a Street and Area Lighting Service is Discontinued pursuant to Regulation 11 (a), (b) or (c), or 9 (i), or when a Customer requests removal of existing fixtures, poles, and/or underground wiring, the Customer shall pay at the time of removal an amount equal to the unrecovered capital cost, plus the cost of removal less any salvage value of only the poles and/or underground wiring to be Discontinued or removed.

(ii) If a Customer requests the subsequent replacement of the fixture, either immediately or at any time within 12 months by another, whether or not of the same type or size, the Customer shall pay, in advance, an amount equal to the unrecovered capital cost of the fixture removed, plus the cost of removal, less any non-luminaire salvage, as well as the monthly charges that would have been incurred over the period if the Service had not been Discontinued.

(iii) Where a Street and Area Lighting Service is Discontinued, any pole dedicated solely to the Street and Area Lighting Service may, at the Customer's request, remain in place for up to 24 months from the date of removal of the fixture, during which time the Customer shall continue to pay the prescribed monthly charge for the pole and underground wiring.

(i) Where Street and Area Lighting fixtures or lamps are wantonly, wilfully, or negligently damaged or destroyed (other than through the negligence of the Company), the Company, at its option and after notifying the Customer by letter, shall remove the fixtures and the monthly charges for these fixtures will cease thirty days after the date of the letter. However, if the Customer contacts the Company within thirty days of the date on the letter and agrees to pay the repair costs in advance and all future repair costs, the Company will replace the fixture and rental charges will recommence. If any future repair costs are not paid within three months of the date invoiced, the Company, after further notifying the Customer by letter, may remove the fixtures. In all such cases the fixtures shall not be replaced unless the Customer pays to the Company in advance all amounts owing prior to removal plus the cost of removing the old fixtures and installing the new fixtures.

(j) Where a Service other than Street and Area Lighting Service is not provided to the Customer for the full monthly billing period or where Street and Area Lighting Service is not provided for more than seven (7) days during the monthly billing period, the relevant charge to the Customer for the Service for that period may be prorated except where the failure to provide the Service is due to the Customer or to circumstances beyond the reasonable control of the Company.

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(k) Where a Customer's Service is at primary distribution or transmission voltage and the Customer provides his own transformation and all other facilities beyond the designated point of supply the monthly demand charge shall, subject to the minimum monthly charge, be reduced as follows:

(i) for supply at 4 kV to 25 kV	$0.40 per kVA
(ii) for supply at 33 kV to 138 kV	$0.90 per kVA

(l) Where a Customer's monthly demand has been permanently reduced because of the installation of peak load controls, power factor correction, or by rendering sufficient equipment inoperable, by any means satisfactory to the Company, the monthly demands recorded prior to the effective date of such reduction may be adjusted when determining the Customer's demand for billing purposes thereafter. Should the Customer's demand increase above the adjusted demands in the following 12 months, the Customer will be billed for the charges that would have been incurred over the period if the demand had not been adjusted.

(m) Charges may be based on estimated readings or costs where such estimates are authorized by these Regulations.

(n) An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new Serviced Premises. Landlords will be exempted from the application fee for name changes at Service Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect.

10. BILLING:

(a) The Company shall bill the Customer monthly for charges for Service. However, when a Service is disconnected or a bill is revised the Company may issue an additional bill.

(b) The charges for Street and Area Lighting Service may be included as a separate item on a bill for any other Service.

(c) Bills are due and payable when issued. Payment shall be made at such place(s) as the Company may designate from time to time. Where a bill is not paid in full by the date that a subsequent bill is issued and the amount outstanding is $50.00 or more, the Company may charge interest at a rate equal to the prime rate charged by chartered banks on the last day of the previous month plus five percent.

(d) Where a Customer’s cheque or automated payment is not honoured by their financial institution, a charge of $16.00 may be applied to the Customer’s bill.

(e) Where a Customer is billed on the basis of an estimated charge an adjustment shall be made in a subsequent bill should such estimate prove to be inaccurate.

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(f) Where between normal meter reading dates, one Customer assumes from another Customer the responsibility for a metered Service, or a Service is Discontinued, the Company may base the billing on an estimate of the reading as of the date of change.

(g) Where a Customer has been underbilled due to an error on the part of the Company or due to an act or omission by a third party, the Customer may, at the discretion of the Company, be relieved of the responsibility for all or any part of the amount of the underbilling.

11. DISCONTINUANCE OF SERVICE:

(a) A Service may be Discontinued by the Customer at any time upon prior notice to the Company provided that the Company may require 10 days prior notice in writing.

(b) A Service may be Discontinued by the Company upon 10 days prior notice in writing to the Customer if the Customer:

(i) provided false or misleading information on the application for the Service.

(ii) fails to provide security or guarantee for the Service required under Regulation 4.

(c) A Service may be Discontinued by the Company without notice if the Service was Disconnected pursuant to Regulation 12, and has remained Disconnected for over 30 consecutive days.

(d) When the Company accepts an application for Service, any prior contract for the same Service shall be Discontinued except where an agreement for that service is signed by a landlord under Regulation 11(f).

(e) Where a Service has been Discontinued, the Service may, at the option of the Company and subject to Regulation 12(a), remain connected.

(f) A landlord may sign an agreement with the Company to accept charges for Service provided to a rental premise for all periods when the Company does not have a contract for Service with a tenant for that premise.

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12. DISCONNECTION OF SERVICE:

(a) The Company shall Disconnect a Service within 10 days of receipt of a written request from the Customer.

(b) The Company may Disconnect a Service without notice to the Customer:
- (i) where the Service has been Discontinued,
- (ii) on account of or to prevent fraud or abuse,
- (iii) where in the opinion of the Company the Customer's electrical system is defective and represents a danger to life or property,
- (iv) where the Customer's electrical system has been modified without compliance with the Electrical Regulations,
- (v) where the Customer has a building or structure under the Company's wires which is within the minimum clearances recommended by the Canadian Standards Association, or
- (vi) when ordered to do so by any authority having the legal right to issue such order.

(c) The Company may, in accordance with its Collection Policies filed with the Board, Disconnect a Service upon prior notice to the Customer if the Customer has a bill for any Service which is not paid in full 30 days or more after issuance.

(d) The Company may Disconnect a Service upon 10 days prior notice to the Customer if the Customer is in violation of any provision of these Regulations.

(e) The Company may refuse to reconnect a Service if the Customer is in violation of any provisions of these Regulations or if the Customer has a bill for any Service which is unpaid.

(f) The Company may Disconnect a Service to make repairs or alterations. Where reasonable and practical the Company shall give prior notice to the Customer.

(g) The Company may Disconnect the Service to a rental premises where the landlord has an agreement with the Company authorizing the Company to Disconnect the Service for periods when the Company does not have a contract for Service with a tenant of that premises.

13. PROPERTY RIGHTS:

(a) The Customer shall provide the Company with space and cleared rights-of-way on private property for the line(s) and facilities required to serve the Customer.

(b) The Company shall have the right to install, remove or replace such of its property as it deems necessary.

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(c) The Customer shall provide the Company with access to the Serviced Premises at all reasonable hours for purposes of reading a meter or installing, replacing, removing or testing its equipment, and measuring or checking the connected load.

(d) All equipment and facilities provided by the Company shall remain the property of the Company unless otherwise agreed in writing.

(e) The Customer shall not unreasonably interfere with the Company's access to its property.

(f) The Customer shall not attach wire, cables, clotheslines or any other fixtures to the Company's poles or other property except by prior written permission of the Company.

(g) The Customer shall allow the Company to trim all trees in close proximity to service lines in order to maintain such lines in a safe manner.

(h) The Customer shall not erect any buildings or obstructions on any of the Company's easement lands or alter the grade of such easements by more than 20 centimetres, without the prior approval of the Company.

14. COMPANY LIABILITY:

The Company shall not be liable for any failure to supply Service for any cause beyond its reasonable control, nor shall it be liable for any loss, damage or injury caused by the use of Services or resulting from any cause beyond the reasonable control of the Company.

15. GENERAL:

(a) No employee, representative or agent of the Company has the authority to make any promise, agreement or representation, whether verbal or otherwise, which is inconsistent with these Regulations and no such promise, agreement or representation shall be binding on the Company.

(b) Any notice under these Regulations will be considered to have been given to the Customer on the date it is received by the Customer or three days following the date it was delivered or mailed by the Company to the Customer's last known address, whichever is sooner.

SECTION 1: INTRODUCTION

1.1 APPLICATION BACKGROUND

1.1.1 About Newfoundland Power

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") business is principally electricity distribution and customer service delivery. Newfoundland Power's electricity system is mature and serves a relatively low growth market.

Newfoundland Power is dependent upon Newfoundland and Labrador Hydro ("Hydro") to supply 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 2013 to 2017F.

Table 1-1
Customers and Sales
2013 to 2017F

	2013	**2014**	**2015F**	**2016F**	**2017F**
Customers	255,618	258,879	261,093	263,089	264,931
Sales (GWhs)	5,763	5,899	5,963	5,985	5,990

From 2013 to 2017F, the number of customers served by the Company is expected to increase by an average of approximately 0.9% per year. Annual weather adjusted sales are expected to increase by an average of approximately 1.0% per year over this period.

For the 2016/2017 test period, growth is expected to be lower than these averages due to a declining provincial economy. This outlook is reflected in all markets the Company serves. For example, the winding down of construction at Vale's hydromet facility and completion of the Hebron offshore platform will be primarily responsible for reduced sales of almost 7% to Newfoundland Power's largest General Service customer class in 2017, when compared to 2015 levels. Domestic customers, which make up the vast majority of the customers served by the Company, are expected to use approximately 1% more energy in 2017 than in 2015.

Newfoundland Power's longer-term outlook for growth in the number of customers and sales is also modest. This reflects longer-term economic and demographic trends.

1.1.2 Newfoundland Power Performance

Service responsiveness, system reliability and effective cost management are hallmarks of a well-run electrical utility.

Newfoundland Power is responsive to its customers' service expectations.

Increasing the Company's capability to respond to customers via digital and mobile channels is one indicator of this responsiveness. The continuing evolution of Newfoundland Power's customer energy conservation programming under the *takeCHARGE* banner is another. Improvements in the speed of new service connections to customers also help the Company better meet its customers' expectations.

Effective response to customer outages is a key expectation of Newfoundland Power's customers. When customer outages occur, the Company's response is effective. This is the result of a combination of factors. One is the Company's continued deployment of resources throughout its service territory in a way that enables effective response to customer outages when they occur. Another is the Company's better deployment of technology to more efficiently schedule and dispatch work. In routine operating conditions, it takes the Company approximately ½ the time to restore service to customers following an outage than the average of its Canadian peers. In 2014, the Company's restoration time was approximately ⅓ the Canadian average.

Newfoundland Power's electrical system performance is reliable.

Newfoundland Power is focused on maintaining the condition of its electrical system on a continuing basis. Its reliability management practices are directed at addressing the leading causes of customer outages in a systematic manner. These practices have yielded tangible outcomes for customers.

Equipment failure is the leading cause of customer outages caused by Newfoundland Power's electrical system. The number of customer outages attributable to equipment failure on the Company's electrical system has decreased by approximately 20% since 2010. Scheduled system maintenance is another prominent cause of customer outages. The number of customer outages attributable to scheduled maintenance on the Company's electrical system has also decreased by approximately 20% since 2010.

Overall, Newfoundland Power's electrical system reliability compares favorably to other utilities. Since 2010, the average duration of customer outages resulting from failures on the Company's electrical system is approximately ½ the Canadian average.

Newfoundland Power's utility operations are efficiently managed.

Labour costs account for approximately 60% of the Company's annual operating expenditures. These costs are those over which Newfoundland Power can exert the greatest degree of managerial control.

In the 4 year period ending in 2017, Newfoundland Power expects its operating labour costs to increase at a rate that is approximately 2.2% per year *lower* than labour cost inflation. Over this period, the Company expects to serve an additional 9,300 customers which represents an increase of 0.9% each year.

The Company achieves sustainable levels of long-term operating efficiency by pursuing a variety of initiatives. Some, such as the proposed accelerated adoption of automated meter reading, provide more significant efficiency improvements. Others, such as increased use of digital customer service technologies, provide smaller efficiency improvements. All efficiency improvements, great and small, contribute to the overall productivity of Newfoundland Power. These efficiencies are reflected in the customer rates proposed in the 2016/2017 General Rate Application.

The Company has also been responsive to developments in the electricity sector since its last general rate application. Following outages in 2013, Newfoundland Power reassessed some key aspects of its customer service response in major electrical system outages. This reassessment resulted in changes to customer communication technology, overall outage response processes and human resource deployment. Following system events in 2014, Newfoundland Power reassessed some key aspects of both its customer service and field response to major system events to further improve response capabilities. These changes contribute to improved Company emergency preparedness and customer responsiveness. Improved preparedness should, in turn, contribute to improved Newfoundland Power response when emergency conditions arise.

1.1.3 Electricity Sector Developments

The Island Interconnected system which serves Newfoundland Power's customers integrates Newfoundland Power's and Hydro's electrical systems. The reliability that Newfoundland Power's customers experience reflects the reliability of both systems. Developments in the electricity sector since the filing of Newfoundland Power's last general rate application in 2012 provide essential context for the consideration of Newfoundland Power's 2016/2017 General Rate Application.

In January 2013, an electrical problem at Hydro's Holyrood thermal generating station caused the plant to disconnect from the electrical system. This outage resulted in approximately 173,000 Newfoundland Power customers losing electrical service. It was approximately 2 days before service was fully restored to all of the Company's customers.

In January 2014, a combination of wholesale supply shortages and successive major equipment failures on Hydro's system resulted in a series of electrical system disruptions over a 6 day period. These disruptions resulted in as many as 188,000 Newfoundland Power customers being without electrical service. The system conditions required power rationing over the 6 day period.

In March 2015, Hydro generation issues on the Avalon Peninsula resulted in wholesale supply shortages. These supply shortages resulted in up to 83,000 Newfoundland Power customers being without electrical service for the morning of March 4, 2015. Power rationing was required during this period of supply shortage.

The Board has a continuing investigation into the circumstances surrounding, and causes of, these power outages and supply shortages. However, it appears that a higher risk of these types of events will exist at least until the completion of Nalcor Energy's Muskrat Falls hydroelectric generating plant and the interconnection of the island electrical system to the North American grid. The current public indications are that completion of the Muskrat Falls development and interconnection of the island electrical system to the North American grid will not occur around mid-2018 as originally forecast.

The interconnection to the North American grid is a transformative event for the electrical system that currently serves the island of Newfoundland. It also creates significant uncertainties for Newfoundland Power and the customers it serves.

How the costs of the Muskrat Falls development and the transmission systems necessary to create the interconnection will be recovered from Newfoundland Power's customers is part of that uncertainty. The reliability of wholesale supply for the Company and, indirectly, Newfoundland Power's customers after interconnection, is another part of that uncertainty. These matters will likely be considered by the Board over the next 2 to 4 years. It is already clear, however, that the interconnection as currently proposed will have significant potential consequences for the future cost and reliability of electrical service for Newfoundland Power's customers.

1.1.4 Risk and Return

A central issue in this Application is Newfoundland Power's cost of capital.

The Board will consider an appropriate capital structure for rate making purposes and an appropriate return on common equity invested in the Company. In addition, the Board will again consider the use of an automatic adjustment formula to annually establish the Company's cost of equity following the 2016/2017 test period.

The business risks to which Newfoundland Power is exposed are not static.

Some of these risks have been described in prior general rate applications. For example, the Company's service territory is exposed to some of the most extreme weather conditions for electricity system operations in Canada. Blizzards and freezing rain conditions reflect one seasonal dimension. Increased frequency of tropical storms and hurricanes reflect another dimension.

Another feature of business risk is forecast provincial demographic trends. The population of Newfoundland and Labrador is forecast to decline. It is aging at the fastest rate in Canada. These customer demographic trends have implications for the longer-term economic outlook in the Company's service territory and, in turn, the risk associated with utility investment and long-term cost recovery.

Since Newfoundland Power filed its last general rate application in 2012, 2 specific risks to which the Company's business is exposed have increased. First, there is the provincial economic outlook. That outlook through the 2016/2017 test period is more negative than the outlook that existed in 2012. This increases the near-term economic risks to which the Company is exposed. Second, there is the risk associated with the wholesale power supply upon which the Company is dependent. This has both short and long-term dimensions. Recent developments in the electricity sector clearly indicate that the uncertainties associated with wholesale electricity supply have also increased since 2012.

1.2 APPLICATION PROPOSALS

1.2.1 2016 and 2017 Revenue Requirements

In this Application, Newfoundland Power is requesting an average increase in current customer rates of approximately 3.1%, effective July 1, 2016. This increase is primarily the result of 3 changes in the Company's cost of service.

Approximately 1.4% of the proposed rate increase relates to changes in Newfoundland Power's costs since its last general rate application. This includes the cost of continuing investment in the electrical system. It also includes increases in operating costs, but at a rate that is less than inflation, and a reduction in costs associated with employee future benefits. Finally, the impact of cost amortizations and new depreciation rates as proposed in the Application are included amongst these cost changes.

The second change in Newfoundland Power's cost of service relates to recovery of wholesale 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 2016 and 2017 supply costs with revenue from rates accounts for an approximate 0.9% 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 as part of the Company's 2008 General Rate Application.

The third cost change relates to Newfoundland Power's future return on equity. In this Application, the Company has filed expert evidence indicating that a fair return for Newfoundland Power in 2016 and 2017 is 9.5% on a 45% common equity ratio. This is higher than the ratemaking return on equity approved by the Board since 2012 of 8.8% on a 45% common equity ratio. Increasing Newfoundland Power's ratemaking return on equity for 2016 and 2017 accounts for an approximate 0.8% increase from current customer rates.

1.2.2. Customer Rates

While this Application proposes an *average* increase in customer rates of 3.1%, the proposed rate increases by customer class are not uniform. To ensure the maintenance of class revenue to cost ratios within a range of 90% to 110% requires that the rate increase for Newfoundland Power's Domestic customers be 3.6% while customers served under General Service Rate 2.3 will receive a rate increase of 0.6%.

Newfoundland Power is also proposing the introduction of separate basic customer charges for unmetered service, single phase service and three phase service for General Service Rate 2.1. This change is a result of the Company's comprehensive retail rate review which was commenced by agreement following the Company's 2008 General Rate Application.

1.2.3 Other Proposals

In this Application, Newfoundland Power is not proposing that the Board reinstate the use of an automatic adjustment formula to annually establish the Company's cost of equity following the 2016/2017 test period. Since Newfoundland Power's last general rate application, there has not been an appreciable change in long Canada bond yields which form the basis of the operation of an automatic adjustment formula. Accordingly, in the Company's view, the current circumstances do not justify reinstating the use of an automatic adjustment formula.

SECTION 2: CUSTOMERS

2.1 OVERVIEW

Newfoundland Power expects to serve a total of approximately 265,000 customers by 2017. The Company is focused on managing its interactions with customers in a manner that is consistent with the least cost provision of service.

Customers increasingly choose digital and technological means to interact with the Company. This is particularly so in situations of electrical system distress and customer outages. In response to this, Newfoundland Power continues to expand existing systems and introduce new technologies to meet customers' evolving needs for information.

Newfoundland Power has historically been able to achieve a reasonable balance between responding to customers' service expectations and least cost operations. The following evidence outlines the Company's plans to continue to do so through 2017.

Prior to 2013, the level of customer satisfaction with the service provided by Newfoundland Power had been relatively consistent. The electrical system events of January 2013 and 2014 were not well received by the Company's customers. This confirms that customer satisfaction with the service Newfoundland Power provides is influenced by the reliability of that service.

Customer demand for energy conservation programming continues to be high. In 2015, Newfoundland Power and Hydro developed a new five-year Conservation Plan. This Plan outlines proposed customer program offerings through 2020, which may be modified once

greater clarity is available following the interconnection of Nalcor Energy's Muskrat Falls project.

2.2 SERVING CUSTOMERS

2.2.1 Customers

Table 2-1 shows the number of Newfoundland Power customers for the period 2013 through the 2017 test year.[1]

Table 2-1
Customers
2013 to 2017F

	2013	2014	2015	2016	2017
Customers	255,618	258,879	261,093	263,089	264,931

For the 4 years ending in 2017, the Company expects an increase of approximately 9,300 customers. This is an increase of approximately 3.6% in the total number of Newfoundland Power customers over the period.

2.2.2 Customer Expectations

The expectations of Newfoundland Power's customers evolve over time. This evolution reflects a variety of influences. Amongst those influences are developments in information technology, changes in customer demographics and offerings of other service providers.

Developments in information technology present greater opportunity for Newfoundland Power to provide new services for its customers. Demographic changes can also impact overall customer

[1] See *Section 6.2.2.: Forecast*, Table 6-2 for details of the number of customers by rate class for the period 2015F through 2017F.

expectations. For example, increasing numbers of Newfoundland Power's customers prefer to deal with the Company through digital channels as opposed to telephonic channels. The offerings of other service providers also affect expectations. The more widespread a particular service offering becomes, the greater the likelihood that Newfoundland Power's customers will expect the Company to provide that particular offering.

Table 2-2 shows the number of Newfoundland Power customer initiated contacts received via telephone at the Customer Contact Centre and via the Company's website from 2011 to 2014.

Table 2-2
Customer Initiated Contacts
2011 to 2014
(000s)

	2011	**2012**	**2013**	**2014**
Telephone	477	454	451	478
Website	542	635	1,005	2,487
Total	**1,019**	**1,089**	**1,456**	**2,965**

In 2011, customer initiated contacts with Newfoundland Power through the Company's website exceeded customer initiated contacts by telephone for the first time. Since 2011, the trend has indicated an increasing preference by customers for digital interaction with the Company.

Over the period 2011 to 2014, the number of customer inquiries to Newfoundland Power via telephone has essentially remained flat. During this period, the number of customers served by Newfoundland Power increased by 15,453, or approximately 6.3%.

Improved capability to interact with customers digitally can be particularly critical in severe outage situations. In such situations, it is common for utility call centre capabilities to be overwhelmed. The inability for customers who are without service to obtain real-time information on electrical system conditions simply adds to customer frustration. For this reason, improved customer interaction capabilities via digital means have become a customer service priority for the Company.

Table 2-3 shows a summary of individual customer inquiries or contacts Newfoundland Power received during the supply shortage and outage events of January 2-8, 2014.

Table 2-3
Customer Inquiries
January 2-8, 2014

Source	**Number of Inquiries**
Customer calls	139,335
Website visits	947,215
New Twitter followers	6,561
Facebook page likes	4,119
Emails	240

During January 2-8, 2014, digital interaction between the Company and its customers was almost 7 times the level of telephonic interaction.[2] This was a significant increase in the level of digital communication from a similar supply shortage experienced during January 11-13, 2013.[3] During the period between the supply shortage events, Newfoundland Power implemented changes to

[2] 947,215 + 6,561 +4,119 + 240 = 958,135. 958,135/139,335 = 6.9.

[3] In January 11-13, 2013, the Company received 156,500 website visits. This was approximately 1/6th the volume of website visits received during the January 2-8, 2014 system events (947,215/156,500 = 6). Part of the increased volume of website visits during January 2-8, 2014 resulted from the increased duration of the system events when compared to January 11-13, 2013. However, part of the increase appears attributable to increasing customer expectations for real-time information on electrical system conditions.

strengthen its website to support its outage communication capabilities with its customers. This included upgrades to the Company website to permit improved customer access to outage related information.[4] These changes enabled the Company to better respond to the events of January 2-8, 2014.[5]

The Company has continued to improve its overall capability to deal with its customers via digital means. This includes modifying the Company's website to better permit customers to access information from mobile devices.[6] It also includes implementation of a SMS notification system for power system outages.[7]

Telephonic communications continue to play a central role in customer service for Newfoundland Power. In 2016, the Company intends to upgrade the current call management technology in use at its Customer Contact Centre.[8] Improvements to the Company's interactive

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[4] This included an interactive outage map, list of known customer outages and informational messages such as outage status. The upgrades also permitted the Company to modify its website during response to major system events so that specific customer messaging for outages (i.e., the safe use of generators) could be exclusively run. Finally, enhancements included an application to permit customers to report outages online.

[5] These improvements are described in the response to Request for Information PUB-NP-025 (1st Revision) filed in the Board's *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System*. The Board's consultants in the Investigation observed that "These improvements played a key role in opening Newfoundland Power's website as a primary communication channel during the January 2014 outages. Recognizing the importance of the website at this time, Newfoundland Power turned the front page of its website into an event outage page as of January 2, 2014. This transformation made it easier for visitors to find relevant outage information. Doing so comprises standard industry practice during large storms or outage events." (See The Liberty Consulting Group *Interim Report*, April 24, 2014, page 74).

[6] Approximately 44% of the 2.5 million website visits in 2014 were made via a smartphone. The approximately 1.1 million mobile device visits in 2014 were more than double the approximately 420,000 visits in 2013. This project is described in Newfoundland Power's *2016 Capital Budget Application, Section 6.1: 2016 Application Enhancements*, page 5, *et. seq*.

[7] The introduction of SMS (short message service) for customer outage alerts was introduced in the 2014-2015 winter season. As of September 30, 2015, 1,269 Newfoundland Power customers have subscribed to the service.

[8] The Company's current call management system was commissioned in 1998 and is at the end of its service life. Next generation technology is expected to provide an increased capacity for the Company to respond to evolving customer requirements. This project is described in Newfoundland Power's *2016 Capital Budget Application, Section 6.2: 2016 System Upgrades*, page 2, *et. seq.*

voice response ("IVR") system to enable high-volume call answering ("HVCA") to better communicate with customers in outage situations are also under consideration.[9]

2.2.3 Balancing Costs & Service

Table 2-4 shows Newfoundland Power's Customer Services costs and Uncollectable Bills for the period 2013 through the 2017 test year.

Table 2-4
Customer Service Costs
2013 to 2017F
($000s)

	2013	2014	2015F	2016F	2017F
Customer Services	9,458	9,750	9,041	9,344	9,115
Uncollectable Bills	897	1,490	1,300	1,327	1,355

Customer Services costs include the costs of Newfoundland Power's day to day commercial interactions with customers. They include the cost of the Company's Customer Contact Centre and customer service staff located in offices across the Company's service territory.

For the 3 years ending in 2015, the variability in the Company's Customer Services costs substantially reflects the impact of electrical system events. When storms, equipment failure or wholesale supply shortages interrupt service to customers, Newfoundland Power is typically

[9] Improvements in HVCA capabilities are being considered for implementation in the 2017-2018 timeframe to enable integration with other system replacements such as the Company's supervisory control and data acquisition ("SCADA") system, which are currently underway. Any project to improve HVCA capabilities would be subject to Board review and approval via the usual capital budget application process.

required to maintain its customer response functions for extended periods of time.[10] This requirement increases Customer Services costs. Efficiency improvements, most notably the proposed acceleration of the Company's adoption of automated meter reading technology ("AMR"), will reduce Customer Services costs in 2016 and 2017.[11] Over the period 2013 through 2017, Customer Services costs are forecast to decrease by approximately 3.6%.

Table 2-5 shows the number of customer initiated telephone contacts which were handled by a customer service representative ("CSR") and the number handled by the Company's IVR system from 2011 to 2014.

Table 2-5
Customer Telephone Calls
2011 to 2014
(000s)

	2011	**2012**	**2013**	**2014**
CSR	290	282	278	287
IVR	187	172	173	191
Total	**477**	**454**	**451**	**478**

The difference in cost for a customer inquiry handled by a CSR or handled by the IVR system is significant. The average cost of a customer inquiry handled by a CSR is over $8.[12] By contrast, the cost of an IVR response to a customer inquiry is less than 20¢.[13] Response to a customer

[10] For example, during the supply shortage and outage events of January 2-8, 2014, the Company's Customer Contact Centre operated for extended periods of over 80 consecutive hours. To help enable such extended service hours, Newfoundland Power identifies and trains additional employees from staff functions such as human resources, finance, conservation, regulatory, information services and audit to serve in the Customer Contact Centre during major electrical system events.

[11] See page 2-9, lines 6-10.

[12] This includes CSR labour, supervision and support costs, technology maintenance costs and long distance charges.

[13] This includes technology maintenance costs and long distance charges.

inquiry via website self-service options would be even less expensive.[14] Because IVR and website responses to customer inquiries are less expensive than personal service, Newfoundland Power will increase the range of customer options for IVR and the website to encourage more customer use.[15] However, many customer inquiries are unlikely to be capable of satisfactory response other than through a trained CSR.[16]

To effectively manage Customer Services costs, Newfoundland Power encourages customers to interact with it via technology.[17] Table 2-6 shows the number of Newfoundland Power customers participating in electronic billing or *eBills* from 2011 to 2014.

Table 2-6
***eBills* Customers**
2011 to 2014
(000s)

	2011	**2012**	**2013**	**2014**
eBills	45	55	63	72

From 2011 to 2014, the number of Newfoundland Power customers that have chosen to receive

[14] The operating cost associated with a website is practically limited to technology maintenance costs.

[15] Currently, Newfoundland Power's IVR system permits customers to access account balances and payments, submit meter readings, report outages or dangerous conditions and access power outage and restoration information for their specific area. This system was commissioned in 1998 and is at the end of its service life. Next generation technology is expected to enable the Company to expand the IVR and web-based options it provides to customers. Amongst the increased options of the next generation technology will be the capability to webchat with customers; offer customer co-browsing; and integration of telephone, email and social media communications. The IVR replacement project is described in Newfoundland Power's *2016 Capital Budget Application, Section 6.2: 2016 System Upgrades*, page 2 *et. seq.* Any proposed expanded options will be included in future Company capital budget applications.

[16] IVR provides a cost effective and satisfactory response to a number of typical customer inquiries such as what a customer's account balance is. On the other hand, more complex inquiries dealing with matters such as credit or contributions in aid of construction do not lend themselves to satisfactory response via an IVR system.

[17] A good example of this is customer energy conservation. In developing customer energy conservation programming, 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. In 2014, almost 95% of customer interaction concerning conservation programming was via website.

their electricity bills electronically has increased by almost 60%.[18] Newfoundland Power currently has one of the highest proportions of electronically billed customers in the Canadian utility sector.[19] Electronic billing of customers costs Newfoundland Power approximately $9.70/year per customer less than paper billing.[20]

Since 2013, Newfoundland Power has been increasing its use of AMR technology to respond to changing regulatory requirements and industry technology advancements.[21] Newfoundland Power is proposing to accelerate the adoption of AMR to achieve 100% penetration in its service territory by the end of 2017. This initiative is expected to reduce operating costs by approximately $380,000 in 2016 and $650,000 in 2017.[22]

Newfoundland Power continues to meet the reasonable service expectations of its customers. Customer Services costs are expected to decrease by approximately 0.9% per year from 2013 through 2017. In the circumstances, this represents a reasonable balance of costs and service.

Newfoundland Power's Uncollectable Bills have increased since 2013. In 2014, Uncollectable Bills totaled approximately $1.5 million. This represents approximately 0.25% of 2014

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[18] In 2011, Newfoundland Power had 45,389 *eBills* customers. In 2014, the Company had 72,277 *eBills* customers (72,277 – 45,389 = 26,888. 26,888/45,389 = 0.592.)

[19] In a November 2014 Canadian Electricity Association quick poll on eBilling, Newfoundland Power's proportion of customers which were electronically billed was indicated to be second to BC Hydro.

[20] This amount reflects avoided printing, paper, envelope and postage charges. It does not include embedded labour and equipment costs associated with printing bills as the Company is still required to incur those costs to provide paper bills to its customers. The Canada Post Corporation has indicated that in 2016, commercial postage rates for Newfoundland Power will increase by approximately 4.2%. Higher postage rates would further increase the cost savings associated with electronic billing.

[21] The current status of the Company's AMR initiative is described in Newfoundland Power's *2016 Capital Budget Application*, *Section 4.4: 2016 Metering Strategy*.

[22] The $380,000 in 2016 includes approximately $290,000 in labour and $90,000 in vehicle costs. The $650,000 in 2017 includes approximately $500,000 in reduced meter reading labour and $150,000 in reduced vehicle costs. Labour savings are reflected in Customer Services costs. Vehicle savings are reflected in Fleet Operations & Maintenance costs. See *Exhibit 1* in *Volume 2, Exhibits & Supporting Materials*.

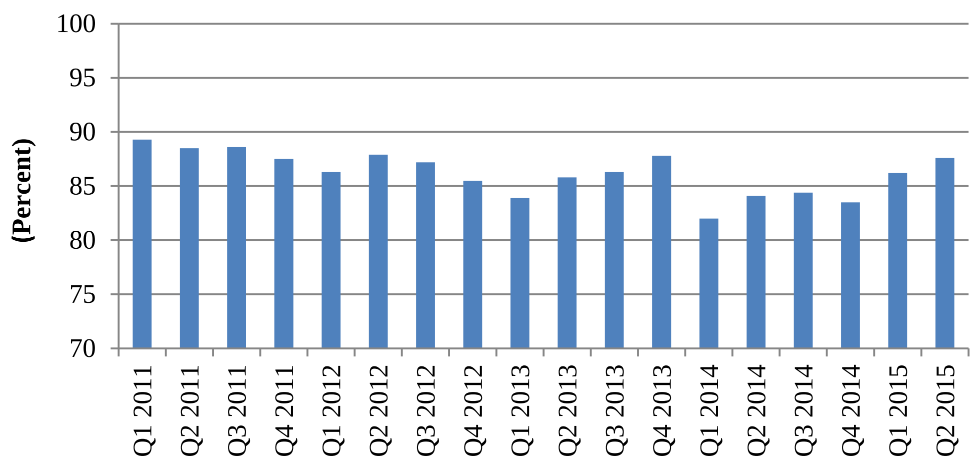
revenue.[23] Newfoundland Power attributes the increase in Uncollectable Bills to changing economic conditions. This level of Uncollectable Bills is not unprecedented. In 1996, Uncollectable Bills totaled approximately $1.4 million or approximately 0.4% of 1996 revenue.[24]

2.2.4 Customer Satisfaction

Each quarter, Newfoundland Power conducts a survey of customers' satisfaction with the service provided by the Company. The results of these surveys provide Newfoundland Power's management with a broad measure of customers' perspectives.

Chart 2-1 shows Newfoundland Power's customer satisfaction index by quarter from 2011 through the first six months of 2015.

Chart 2-1
Customer Satisfaction Index
2011 to 2015
(by quarter)



[23] $1,490,000/$629,772,000 = 0.0024.
[24] $1,400,000/$341,560,000 = 0.0041.

Newfoundland Power's customers' level of satisfaction with the Company's service declined between 2011 and 2014. Customer satisfaction has improved somewhat in 2015. The decline in customer satisfaction is most evident in 2013 and 2014 survey results, particularly those related to the first quarter in each year. This reflects customer dissatisfaction with the significant outages experienced in January 2013 and 2014.[25]

Customer satisfaction survey results, particularly those for 2013 and 2014, highlight the importance of service reliability to Newfoundland Power's customers.[26]

2.3 CUSTOMER CONSERVATION

2.3.1 Assessing Progress

In 2008, Newfoundland Power and Hydro developed a joint plan to implement a portfolio of customer energy conservation programs.[27] In 2009, Newfoundland Power implemented the residential and commercial customer energy conservation programs indicated in this plan. In 2012, Newfoundland Power and Hydro developed the *Five-Year Energy Conservation Plan: 2012 – 2016* which expanded and modified the program portfolio introduced in 2009.

Both Newfoundland Power's customer energy savings and Company costs have been consistent with the Newfoundland Power – Hydro joint plans which have been reviewed by the Board.

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[25] The first quarter survey was conducted after the supply shortage and outage events of January 2-8, 2014 and was affected by customers' view of those events. A similar but less severe decline can be observed in the first quarter 2013 results which reflected customers' views of the significant outage of January 11-13, 2013 arising from the loss of Hydro's Holyrood Unit #1.

[26] To help address customer dissatisfaction associated with the outage events of January 2013 and January 2014, Newfoundland Power is working with Hydro to provide more timely customer notification of anticipated electrical system vulnerabilities that could affect reliability. In 2014, Hydro and Newfoundland Power agreed upon a joint advance notification protocol to guide customer communications when generation reserve margins are forecast to dip below predetermined thresholds.

[27] 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).

Table 2-7 shows energy savings and costs for Newfoundland Power's customer energy conservation programs from 2011 to 2014.

Table 2-7
Energy Conservation Programs
Costs and Savings
2011 to 2014

	2011	**2012**	**2013**	**2014**
Costs (000s)	$3,841	$3,030	$3,654	$5,289
Energy Savings (GWh)	19.8	28.2	36.3	50.0

From 2011 to 2014, the annualized energy saved by Newfoundland Power's customers more than doubled from 19.8 GWh in 2011 to 50 GWh in 2014. This result exceeded the targeted energy savings for Newfoundland Power's customers identified in the *Five-Year Energy Conservation Plan: 2012 – 2016* for 2014. At the currently forecast Holyrood fuel price of 11.6¢/kWh, energy savings of 50 GWh translates into avoided fuel costs of approximately $5.8 million.[28]

Participation in customer energy conservation programs has averaged approximately 5,500 Newfoundland Power customers per year through the 2011 to 2014 period.[29] In addition, 251,791 at-the-cash rebates were given on customers' energy efficient purchases through the instant rebates component of the Small Technologies program in 2014.[30]

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28 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 $0.116/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast of $73.35/barrel for 2015 as reflected in the Rate Stabilization Plan (50,000,000 kWh X $0.116 = $5,800,000).

29 Participation levels by year were 2011: 6,530; 2012: 4,983; 2013: 5,246; and 2014: 5,153.

30 The Small Technologies program was part of the *Five-Year Energy Conservation Plan: 2012 – 2016* which was before the Board at Newfoundland Power's *2013/2014 General Rate Application*.

In 2014-2015, Newfoundland Power undertook a pilot program to assess the economic, market and technical feasibility of direct residential hot water load control to reduce overall peak demand. The pilot was initiated in response to the constraints on the Island Interconnected system that became evident after the events of January 2013 and January 2014.[31] The pilot indicated that a large scale program which could achieve demand reductions of approximately 14 MW by 2020 was technically feasible but not economically justified.[32]

Interest in customer energy conservation programming remains strong. In 2011, the *takeCHARGE* website received 72,996 visits. In 2014, website visits had more than doubled to 186,003. For the first 7 months of 2015, the number of website visits has already reached 197,973. Approximately 80% of the website visits in 2015 were via a mobile device.[33] This reflects the original intention to use the *takeCHARGE* website as the primary resource for customer conservation interaction.

2.3.2 Future Customer Conservation Programming

Five-Year Conservation Plan: 2016-2020

Newfoundland Power and Hydro recently reassessed the portfolio of customer energy conservation programs to incorporate lessons learned since 2009.[34] An updated Conservation Potential Study

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[31] The pilot program involved control of 500 electrical hot water tanks in customer homes in the northeast Avalon. Average demand reduction achieved was 0.6 kW per participant. Total demand reduction achieved was approximately 300 kW.

[32] The program was evaluated against Hydro's most current marginal cost projection for the Island Interconnected system. This evaluation indicated that program costs of approximately $22.6 million over 10 years would yield demand savings of only approximately $17.1 million. The forecast Total Resource Cost test result of 0.8 fails to meet the required 1.0 result necessary to justify implementation of a conservation program.

[33] In September 2015, the takeCHARGE.nl.ca website was updated to better enable customers to access information from mobile devices.

[34] Periodic reassessments of the customer program portfolio were envisaged in the *Five-Year Energy Conservation Plan: 2008 – 2013*, as well as in the *Five-Year Energy Conservation Plan: 2012 – 2016*.

that was completed in 2015 formed part of this reassessment.[35] The Conservation Potential Study included consultation with interested parties including customers, trade allies and retail partners.[36]

This reassessment resulted in the creation of the *Five-Year Conservation Plan: 2016 - 2020*. The *Five-Year Conservation Plan: 2016 - 2020* is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 1*.

The principal changes to customer conservation programming contained in the *Five-Year Conservation Plan: 2016 – 2020* relate to (i) expansion of current programs, particularly for commercial customers;[37] (ii) introduction of a new residential Benchmarking program;[38] and (iii) discontinuation of certain residential incentives.[39] In addition, the development of an educational initiative to promote mini split heat pumps is planned for 2016.

The *Five-Year Conservation Plan: 2016 – 2020* evaluates the cost effectiveness of customer energy conservation programs based upon the Total Resource Cost ("TRC") test and the Program

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35 The Conservation Potential Study provides a framework for utilities to properly examine conservation opportunities. The primary outcomes of the study are (i) identification of cost-effective energy saving and demand management measures; (ii) general parameters for program development and (iii) quantification of achievable energy savings and demand management potential by sector and end-use. These outcomes form the basis for long-term planning, including energy savings targets, specific program design, implementation, evaluation and program delivery budgets. This study was an update to the Conservation Potential Study that was completed in 2008.

36 Consultations were conducted over a 3 day period in April 2015. In addition, a presentation was made to the Consumer Advocate and Board staff on the Conservation Potential Study and the conservation planning process.

37 In 2016, the Company intends to expand its technology offerings within the Business Efficiency Program as well as the Instant Rebate component of the Small Technologies program. See the *Five-Year Conservation Plan: 2016 - 2020, Volume 2, Exhibits & Supporting Materials, Reports, Tab 1.*

38 In 2016, the Company intends to develop and offer a Benchmarking program that promotes changes to customer behaviour to encourage more efficient use of electricity. See the *Five-Year Conservation Plan: 2016 - 2020, Volume 2, Exhibits & Supporting Materials, Reports, Tab 1.*

39 The Company intends to conclude the Appliance and Electronics component of the Small Technologies program in 2017, followed by the conclusion of the Instant Rebates component in 2018. The anticipated discontinuation of this program is due to the changing marginal costs on the electricity system and the expectation that LEDs will have transformed the residential lighting market by 2018.

Administrator Cost ("PAC") test. Prior plans evaluated customer energy conservation programs based upon the TRC test and the Rate Impact Measure test. The Rate Impact Measure test is no longer widely used in evaluation of customer energy conservation programs.[40] Use of the TRC test and PAC test is consistent with current Canadian utility practice for evaluating the cost effectiveness of customer energy conservation programs.[41]

In Order No. P.U.7 (1996-1997), the Board required customer conservation programs to be evaluated by use of the Rate Impact Measure test and the TRC test. Adoption of the TRC test and PAC test by Newfoundland Power as proposed in the *Five-Year Conservation Plan: 2016 – 2020* will require the Board to reconsider the terms of Order No. P.U.7 (1996-1997).

Newfoundland Power expects to implement these changes in customer energy conservation program evaluation in the 2016 and 2017 test period. Further revision to program evaluation and the *Five-Year Conservation Plan: 2016 – 2020* may be necessary to reflect the interconnection of Nalcor Energy's Muskrat Falls project.[42]

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[40] Currently, it appears the only 2 Canadian jurisdictions that continue to use the rate impact measure as a benefit cost test for program screening are Manitoba and Quebec. Only 2% of U.S. jurisdictions still use the Rate Impact Measure test.

[41] All Canadian jurisdictions use the TRC test as their primary benefit cost test for program screening. The majority of Canadian jurisdictions use the PAC test as a secondary test. In the U.S., approximately 70% of jurisdictions use the TRC test as a primary cost benefit test for evaluating program cost effectiveness.

[42] The marginal costs used in 2015 to evaluate cost effectiveness of customer energy conservation programs are based on the most recent marginal cost forecast as projected by Hydro in February 2015. These estimates are currently under review by Hydro, including consideration of the current forecast for interconnection of Nalcor Energy's Muskrat Falls project. Once more current estimates are available, they will be incorporated in the evaluation process.

Energy Savings and Cost Outlook

Table 2-8 shows energy savings for Newfoundland Power's customer energy conservation programs from 2009 to 2017F.[43]

Table 2-8
Energy Conservation Programs
Energy Savings
2009 to 2017F
(GWh)

	2009-2014	**2015F**	**2016F**	**2017F**	**Total**
Residential	129.3	57.5	71.7	93.2	**351.7**
Commercial	15.4	9.8	16.6	24.8	**66.6**
Total	**144.7**	**67.3**	**88.3**	**118.0**	**418.3**

In 2017, the Newfoundland Power customer energy conservation program portfolio is forecast to achieve approximately 118 GWh in annual gross customer energy savings.[44] From 2009 to 2017, the cumulative gross customer energy savings are forecast to be approximately 418.3 GWh.

[43] The energy savings indicated represent *gross* energy savings achieved by customers in each period. 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 2017F are estimated to be 246.5 GWh.

[44] For 2016 and 2017, additional gross customer energy savings of approximately 25.5 GWh per year are forecast. ((118.0 – 88.3) + (88.3 – 67.3)) / 2 = 25.5 GWh.

Table 2-9 shows customer energy conservation costs for Newfoundland Power from 2009 to 2017F.

Table 2-9
Customer Energy Conservation Costs
2009 to 2017F
($000s)

	2009-2014	2015F	2016F	2017F	Total
General	4,388	767	778	801	**6,734**
Program	16,523	5,876	6,544	7,231	**36,174**
Total	**20,911**	**6,643**	**7,322**	**8,032**	**42,908**

For 2016 and 2017, total customer energy conservation costs are forecast to average approximately $7.7 million per year. This compares to $6.6 million in 2015. The increase in the Company's total customer energy conservation costs primarily reflects the expansion of customer energy conservation program offerings.[45] General customer energy conservation costs, which include the costs associated with customer education and support activities, are expected to remain stable in 2016 and 2017.[46]

[45] In 2016, increased customer energy conservation *program* costs include: (i) expansion of the Business Efficiency program ($175,000); (ii) expansion and increased participation in the Instant Rebates component of the Small Technologies program ($377,000) and (iii) development and implementation of the Benchmarking program ($506,000). In 2017, increased customer energy conservation *program* costs include: (i) increased participation, marketing and evaluation costs in the Business Efficiency program ($252,000) and (ii) continuation of the Benchmarking program for residential customers ($482,000). Costs associated with the development of an educational initiative to promote mini split heat pumps ($114,000 in 2016; $95,000 in 2017) are reflected in customer energy conservation *general* costs.

[46] Where possible, co-funding with others is pursued to keep conservation costs low. For example, in 2014, *takeCHARGE* partnered with the provincial Office of Climate Change and Energy Efficiency to extend school information programs. In the 2014-2015 school year, over 11,000 students in 106 schools throughout the Province participated in 448 presentations about energy efficiency and conservation.

From 2009 to 2017, Newfoundland Power expects to spend a total of approximately $42.9 million on customer energy conservation.[47] Gross customer energy savings of 418.3 GWh to 2017 are expected. At the current Holyrood fuel price of approximately 11.6¢/kWh, energy savings of 418.3 GWh translates into approximately $48.5 million in aggregate avoided fuel costs by year end 2017.[48]

The gross customer energy savings of 118 GWh annually forecast for year end 2017 are expected to continue beyond the 2016/2017 test period.[49]

Current customer energy conservation programming is consistent with the efficient operation of the Island Interconnected system and is consistent with the least cost delivery of service to customers.

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[47] The levelized utility cost is an industry metric used to assess the costs of energy conservation programs. The levelized utility cost essentially discounts future energy savings resulting from conservation programs to a present value to provide the economic cost to the utility (per kWh) to generate those energy savings. The levelized utility cost only considers *utility* program costs (i.e., development, marketing, incentives and administration costs), not customer costs. For the period 2009 through 2017, the levelized utility cost of Newfoundland Power's customer energy conservation programming is expected to be 3¢/kWh.

[48] The 11.6¢/kWh is based upon a 630 kWh/barrel conversion efficiency and oil price forecast of $73.35/barrel for 2015 as currently reflected in the Rate Stabilization Plan (418,300,000 kWh x $0.116 = $48,522,800). This is a conservative estimate of the value of the avoided fuel costs associated with customer conservation. The average Holyrood oil price forecast for 2009 through 2016 has ranged from $71.45/barrel (2009) to $118.80/barrel (2013) and averaged $92.24/barrel. At the average of $92.24/barrel, avoided fuel costs for the period 2009 through 2017 are approximately $61.5 million (418,300,000 kWh x $0.147 = $61,490,100).

[49] Customer energy conservation programming implemented by year end 2017 is expected to yield annual energy savings of approximately 142.4 GWh, 158.2 GWh and 158.4 GWh, respectively in 2018, 2019 and 2020.

SECTION 3: OPERATIONS

3.1 OVERVIEW

Newfoundland Power's electrical system continues to perform reliably. The average annual duration of outages experienced by customers which were attributable to the Company's electrical system is approximately ½ the Canadian average. The average annual number of outages is consistent with the Canadian average.

Equipment failure, scheduled outages to perform maintenance and weather are the 3 most prominent causes of customer outages on Newfoundland Power's electrical system. In the 5 years to 2014, the Company has been successful in achieving meaningful reductions in the number of equipment failures, the number of customer interruptions required to perform scheduled maintenance and the average time to respond to customer outages. In 2014, excluding significant events, Newfoundland Power's response time following a customer outage was approximately ⅓ the Canadian average.

Newfoundland Power's emergency management practices have historically been effective. Improvements to these practices and improvements to electrical system resilience have been undertaken in response to the electrical system events of January 2014. Further improvements are expected through the 2016/2017 test period.

Newfoundland Power's operating costs are forecast to increase by approximately 1.6% per year for the 4 year period ending in 2017. Operating labour costs, an indicator of management efficiency, are forecast to increase by approximately 1.4% per year over this period. This cost performance reflects a reasonable level of operating efficiency and is

consistent with the reliable, least cost delivery of electrical service to the Company's customers.

Newfoundland Power's capital expenditures vary with the requirements of the Company's electrical system. These costs are also consistent with the reliable, least cost delivery of electrical service to customers.

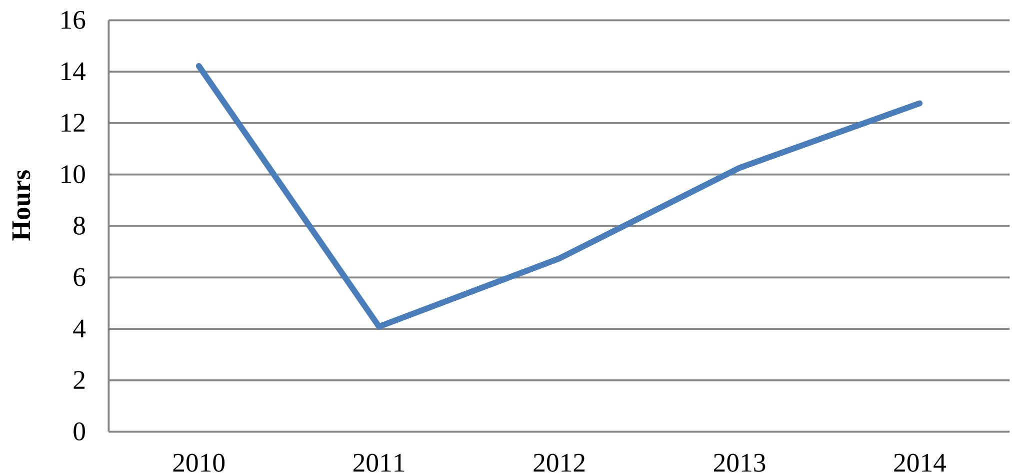
3.2 THE ELECTRICAL SYSTEM

3.2.1 Overall Electrical System Performance

The Island Interconnected system which serves Newfoundland Power's customers integrates Newfoundland Power's and Hydro's electrical systems. For this reason, the overall reliability experienced by the Company's customers reflects the combined performance of both Hydro's and Newfoundland Power's electrical systems.

Chart 3-1 shows the average number of hours Newfoundland Power's customers were without service for each year ("SAIDI") during the period 2010 through 2014.

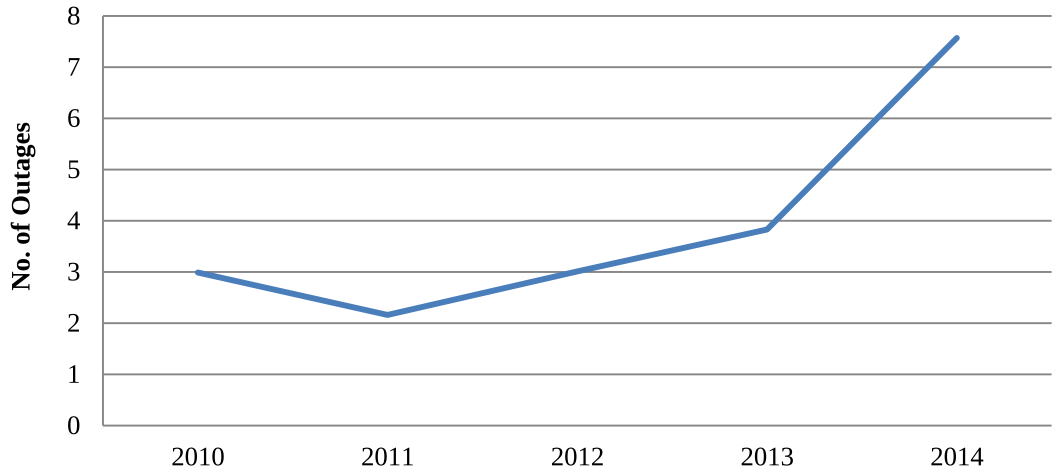
Chart 3-1: SAIDI
Newfoundland Power
2010 to 2014



The duration of outages experienced by Newfoundland Power's customers varies significantly from year to year. These variations typically result from significant weather events, such as hurricanes and ice storms, and loss of supply from Hydro. For example, longer customer outages in 2010 resulted from a combination of an ice storm and Hurricane Igor. In 2013 and 2014, extended customer outages were attributable to loss of supply from Hydro in January of each year.

Chart 3-2 shows the average frequency, or number of outages, experienced by Newfoundland Power's customers in each year ("SAIFI") during the period 2010 through 2014.

Chart 3-2: SAIFI
Newfoundland Power
2010-2014



The frequency of customer outages varies from year to year. Significant events, such as extreme weather or system events, which may significantly impact the duration of customer outages, or SAIDI, do not necessarily impact the frequency of customer outages, or SAIFI, in the same way. For example, an extreme weather event such as a hurricane could result in days of customer outage (each day representing a SAIDI of 24) but only result in a single outage. These types of weather events affect SAIDI more severely than SAIFI. Conversely, the system events which occurred in January 2013 and January 2014 resulted in days of customer outage and also a significant number of outages related to successive equipment failures. These events significantly increased *both* SAIDI and SAIFI in those years.

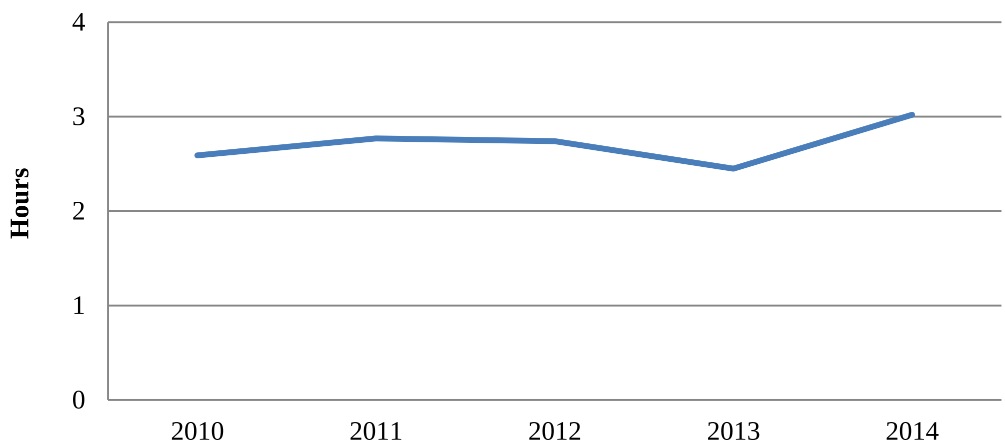
3.2.2 Newfoundland Power's System Performance

Newfoundland Power is responsible for the management of the reliability performance of its electrical system.

The Company's electrical system is constructed and maintained to national standards.[1] Electrical systems, including Newfoundland Power's, are not constructed, or expected, to fully withstand extreme weather conditions such as hurricanes or ice storms. For this reason, the impacts of such extreme conditions, or significant events, are typically excluded from the evaluation of electrical system reliability performance.[2]

Chart 3-3 shows SAIDI for Newfoundland Power's customers during the period 2010 through 2014, excluding the impact of significant events.

Chart 3-3: SAIDI
Newfoundland Power
(excl. significant events)
2010 to 2014



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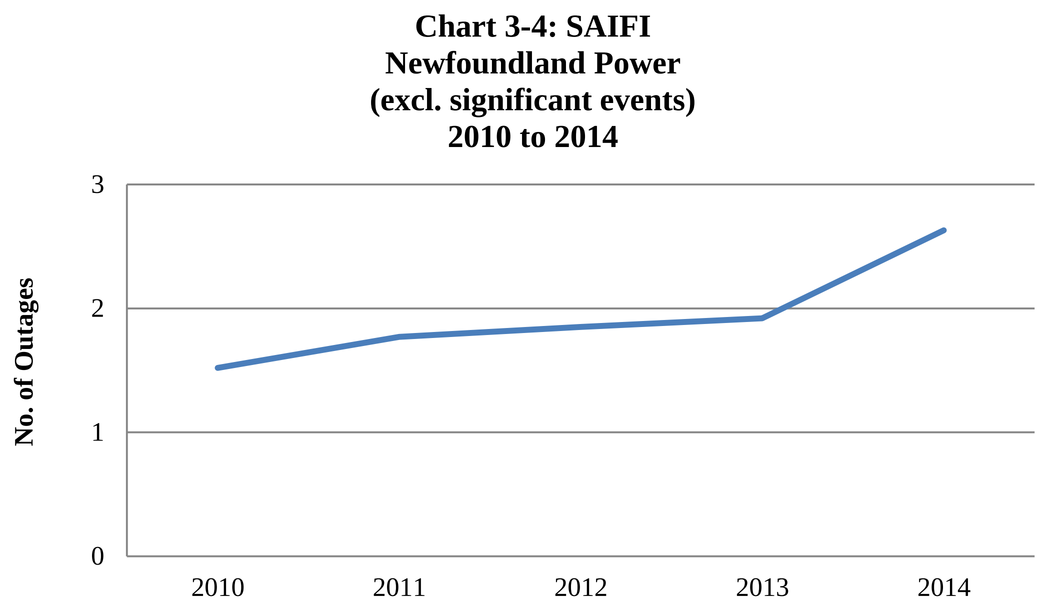
[1] The primary engineering standard is Canadian Standards Association C22.3 No.1, *Overhead Systems*.

[2] The Canadian Electricity Association ("CEA") defines such extreme conditions as *significant events* which are defined as "events that exceed reasonable design and/or operational limits of the electrical power system". Examples of significant events include hurricanes, ice storms and loss of supply, such as the generation shortages that occurred on the Island Interconnected system in January 2013 and January 2014.

When significant events are excluded, the duration of outages experienced by Newfoundland Power's customers has remained relatively consistent at approximately 2 to 3 hours per year over the period 2010 through 2014.

Chart 3-4 shows SAIFI for Newfoundland Power's customers during the period 2010 through 2014, excluding the impact of significant events.



When significant events are excluded, the frequency of outages for Newfoundland Power's customers has remained relatively consistent between 1 and 3 outages per year over the period 2010 through 2014.

In 2014, Newfoundland Power experienced an unusually high incidence of winds in excess of 100 km/hr in its service territory.[3] The increased number of wind events did not constitute a significant event for the purposes of reliability analysis. This increased incidence of high winds in 2014 was a significant contributor to the increased number (i.e., SAIFI) and duration of outages (i.e., SAIDI) for Newfoundland Power's customers that year. The impact of wind in 2014 indicates the effect that higher than normal wind conditions can have on the Company's distribution reliability performance.[4]

3.2.3 Canadian Comparisons

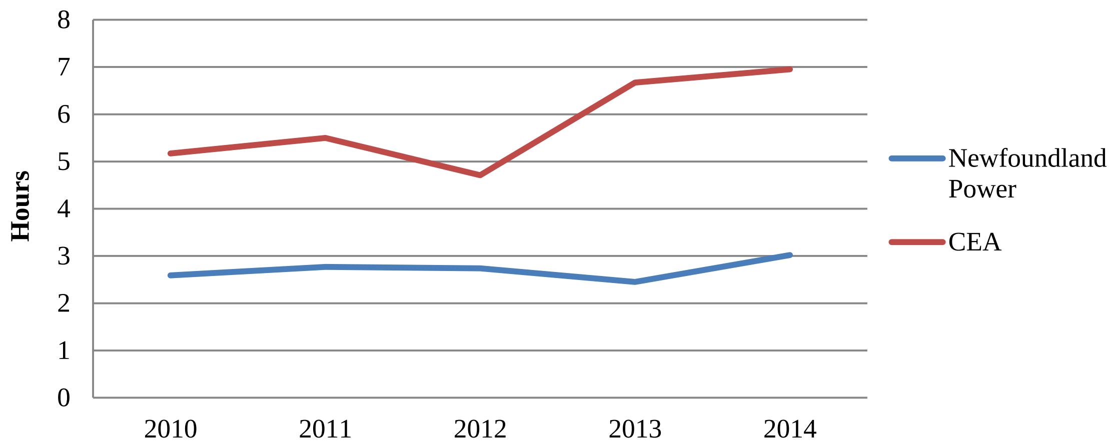
Comparisons of Newfoundland Power's electrical system reliability to Canadian averages also provide a useful perspective on performance.

[3] In 2014, there were a total of 44 days when wind speeds in excess of 100 km/hr were experienced at 1 of the 4 weather stations in the Company's service territory. For the 5 years ending in 2013, Newfoundland Power experienced an average of approximately 17 days each year when wind speeds were in excess of 100km/hr. The 4 weather stations are located in St. John's, Bonavista, Gander and Stephenville.

[4] A comprehensive assessment of Newfoundland Power's distribution system reliability is contained in the *2015 Distribution Reliability Review* included with the Company's *2016 Capital Budget Application*.

Chart 3-5 compares SAIDI for Newfoundland Power to the Canadian average for the period 2010 through 2014, excluding significant events.[5]

Chart 3-5: SAIDI
Newfoundland Power vs. Canadian Average
(excl. significant events)
2010 to 2014

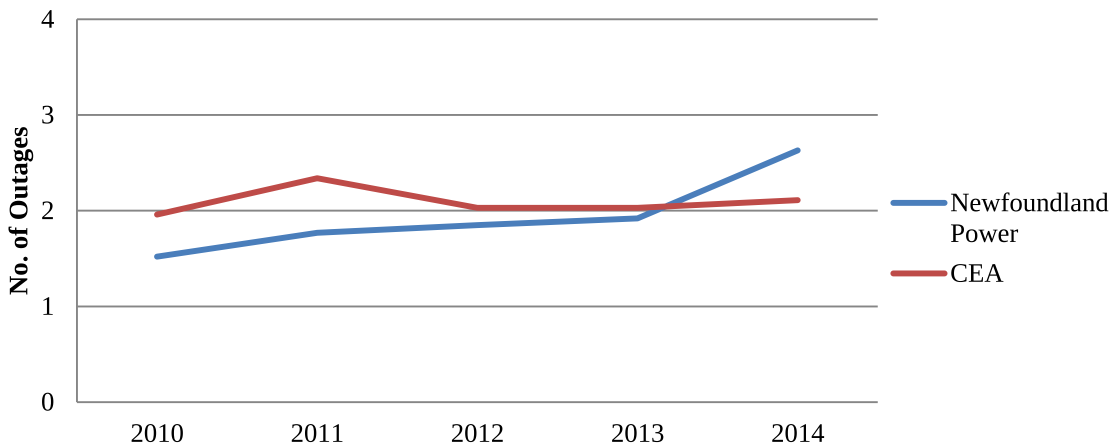


Since 2010, the average annual duration of customer outages experienced by Newfoundland Power's customers due to the performance of the Company's electrical system has consistently been approximately ½ the Canadian average.

[5] References to the *Canadian average* in *Section 3: Operations* refer to Region 2 utilities which are members of the Canadian Electricity Association. Region 2 utilities include Canadian utilities which serve a mix of urban and rural markets. These include ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro Quebec, Manitoba Hydro, Maritime Electric, New Brunswick Power, Newfoundland and Labrador Hydro, Newfoundland Power, Newmarket-Tay Power Distribution, Nova Scotia Power, Northwest Territories Power Corporation, Sask Power, Veridian Connections, Waterloo North Hydro, Yukon Electrical Co. and Yukon Energy.

Chart 3-6 compares SAIFI for Newfoundland Power to the Canadian average for the period 2010 through 2014, excluding significant events.[6]

Chart 3-6: SAIFI
Newfoundland Power vs. Canadian Average
(excl. significant events)
2010 to 2014



During the period 2010 through 2014, the number of outages experienced by Newfoundland Power's customers each year has been broadly consistent with the Canadian average.

3.3 OPERATIONS MANAGEMENT

3.3.1 Reliability Management

General

Effective reliability management practically requires Newfoundland Power to address the primary causes of customer outages in a systematic way. This includes the identification of the primary causes of customer outages and the taking of appropriate steps to reduce the number and duration of those outages.

[6] See footnote 5.

The primary causes of customer outages on Newfoundland Power's electrical system include equipment failure, weather and scheduled outages required to perform system maintenance. Excluding the impact of extraordinary system events, equipment failure has been the leading cause of customer outages on Newfoundland Power's electrical system during the period 2010 to 2014. Weather and scheduled maintenance have been the 2nd and 3rd leading causes of customer outages.[7]

Newfoundland Power's approach to reliability management is focused upon (i) maintenance of the Company's electrical system with a view to reducing customer outages and (ii) maintenance of a robust response capability to address customer outages when they occur.

Maintaining Electrical System Condition

Newfoundland Power is a mature electrical utility. The equipment which makes up its electrical system is aging. This is typical in today's electric utility industry.

Reliability largely reflects the general condition of the electrical system. If equipment is deteriorated or defective, it will be more prone to failure. In virtually all cases of equipment failure, there is usually no question that the equipment needs to be replaced or refurbished. The essential question is how it can be replaced or refurbished in a least cost manner that is consistent with appropriate levels of reliability.

Replacement or refurbishment of equipment which has failed in-service results in higher replacement costs than doing so in a scheduled manner. In addition, in-service failures will

[7] For ½ of the years since 2005, scheduled outages were the 2nd leading cause of customer interruptions on Newfoundland Power's electrical system.

result in more customer interruptions than systematic and scheduled maintenance of the electrical system. For these reasons, replacement or refurbishment of equipment which, through inspection, experience or sound engineering judgment appears to be reasonably close to failure or unreasonably prone to failure, is consistent with least cost delivery of reliable electrical service.[8]

Newfoundland Power's inspection and maintenance programs are aimed at identifying deteriorated electrical equipment in a systematic way. Where possible, equipment is repaired or replaced prior to failure and resulting customer outages. These repairs and replacements may be done immediately if the condition of the electrical equipment requires. Where equipment condition permits, the repairs and replacements are scheduled as part of the Company's ongoing electrical system refurbishment programs.

The cost to replace or refurbish deteriorated or defective equipment is a significant factor in the cost of maintaining or improving the overall level of service reliability. Currently, Newfoundland Power expends approximately $20 million a year in electrical system maintenance. Over the decade to 2014, the Company has spent an average of $40 million a year in the targeted capital replacement of aged and deteriorated equipment.

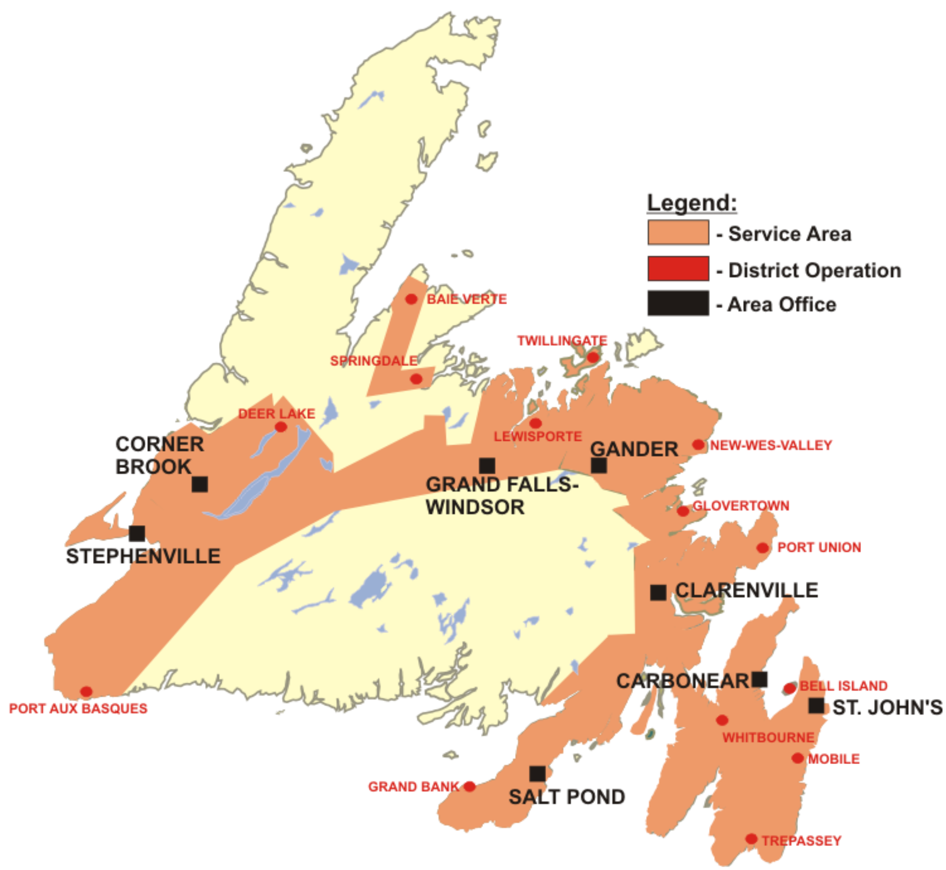
[8] This reasoning also appears consistent with industry best practice. See, for example, *Aging Infrastructures*, Quanta Technology LLC, 2012, page 4 which indicates that "…*programs to manage aging equipment will not be special one-time efforts, which will be executed before the utility goes back to its old processes and procedures. They will be needed on a continuing basis. Thus, some combination of on-going testing, tracking, mitigation of continued deterioration and the effects and failures, and pro-active replacement and refurbishment of deteriorated equipment, will be needed in the long run.*"

1 ***Responding to Outages***

2 Map 3-1 shows Newfoundland Power's distribution service territory, together with the location
3 of the Company's area and district offices.

4

Map 3-1
Newfoundland Power's Service Territory
Area and District Offices



5 Newfoundland Power's distribution service territory is extensive.[9] It is almost 1,000 kilometres
6 from Trepassey, on the Avalon Peninsula, to Port-aux-Basques on the southwest coast. It is over

[9] At approximately 70,000 km^2, Newfoundland Power has the largest distribution service territory in Atlantic Canada. By comparison, Nova Scotia Power's distribution service territory is approximately 27,500 km^2; NB Power's is approximately 50,000 km^2 and Maritime Electric's is approximately 5,600 km^2.

300 kilometres from Grand Bank, on the Burin Peninsula, to Port Union, on the Bonavista Peninsula.

To cost effectively manage reliability, Newfoundland Power deploys employees, vehicles and materials throughout the service territory.[10] This enables the Company to respond quickly to power outages in a safe and efficient manner. Newfoundland Power has maintained a target to arrive at the site of 85% of customer reported trouble calls within 2 hours.[11] Current deployment of employees, vehicles and materials supports the attainment of this target.

3.3.2 Reliability Management Outcomes

Introduction

The effectiveness of Newfoundland Power's approach to reliability management can be seen in a number of tangible outcomes.

These outcomes include reduced numbers of outages due to equipment failures, reduced numbers of outages due to scheduled electrical system maintenance, and reduced restoration times for customers when an outage occurs.

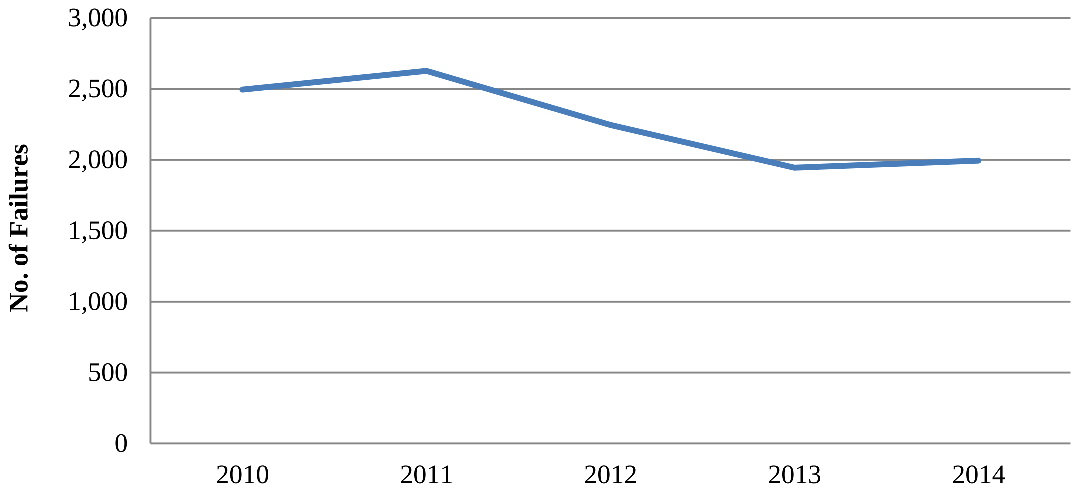
[10] Newfoundland Power has Powerline Technicians situated in 22 locations across its service territory. These 22 locations are also equipped with appropriate vehicles and materials. Technical staff (i.e., technologists and/or engineers) are situated in 9 locations.

[11] This target is applied to routine operating conditions. This target is not applied to major electrical system events, including severe weather events.

Equipment Failures: 2010 to 2014

Chart 3-7 shows the number of equipment failures on Newfoundland Power's electrical system during the period 2010 through 2014.

Chart 3-7: Equipment Failures
Newfoundland Power
2010 to 2014



Between 2010 and 2014, the number of equipment failures on Newfoundland Power's electrical system was reduced by approximately 20%.[12]

Scheduled Outages: 2010 to 2014

Effective maintenance of an electrical system practically requires that electrical equipment be periodically taken out of service. In many cases, this requires customer outages to be

[12] In 2010, Newfoundland Power recorded 2,495 equipment failures on its electrical system; in 2014, there were 1,994 failures. (1,994 – 2,495 = -501. -501/2,495 = -0.201).

scheduled.[13]

Minimizing the customer inconvenience associated with outages required for electrical system maintenance is a key aspect of effective reliability management. Performing maintenance, refurbishment or replacement work while equipment is energized can eliminate the need for a customer outage. So, increasing the amount of maintenance performed on energized equipment can reduce the number of customer outages required to maintain the electrical system in reliable operating condition.[14]

Table 3-1 shows the percentage of the total of scheduled maintenance, refurbishment and replacement of existing utility equipment (collectively "plant upgrades") which was performed by Newfoundland Power on energized electrical equipment for the period 2010 through 2014.

Table 3-1
Plant Upgrades
Energized Equipment
2010 to 2014

2010	2011	2012	2013	2014
40%	46%	49%	51%	53%

Use of mobile generation and transformation facilities can also assist in reducing the number of customer outages required for scheduled maintenance. Newfoundland Power maintains 2 mobile

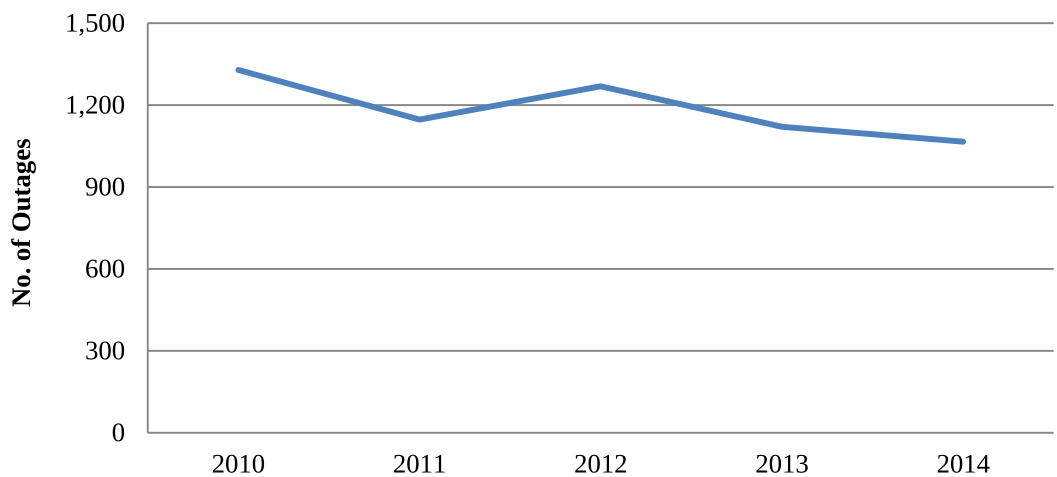
13 Many of Newfoundland Power's customers in rural areas are served by *radial* transmission and distribution systems. Because such systems provide only 1 path of electricity to customers, maintenance of major electrical equipment practically will require customer outages unless other arrangements (i.e., mobile generation or portable substations) are made. In more urban areas, which typically have multiple routings for electricity to customers (i.e., they are *looped* systems), customer outages for maintenance can sometimes be avoided by rerouting power supply.

14 A number of factors can limit the Company's ability to perform maintenance work in an energized environment. Safe work methods are the most prominent of these. In addition, the electrical system configuration or equipment location can also be a limiting factor.

generators; a 2.5 MW mobile diesel generator and a 7.2 MW mobile gas turbine.[15] Newfoundland Power also has 4 portable substations. Mobile facilities, such as portable substations, can be used as a substitute for equipment that must be taken out of service for maintenance. This can avoid the need for customer outages. Mobile generation can be used to provide electricity to customers during maintenance. This also can avoid the need for customer outages for maintenance.

Chart 3-8 shows the number of scheduled outages on Newfoundland Power's electrical system during the period 2010 through 2014.

Chart 3-8: Scheduled Outages
Newfoundland Power
2010 to 2014



[15] The Company's current capital plans include the purchase of an additional mobile generator in the 2017/2018 time period. See *2016 Capital Plan,* June 2015, page 12 filed with Newfoundland Power's *2016 Capital Budget Application*.

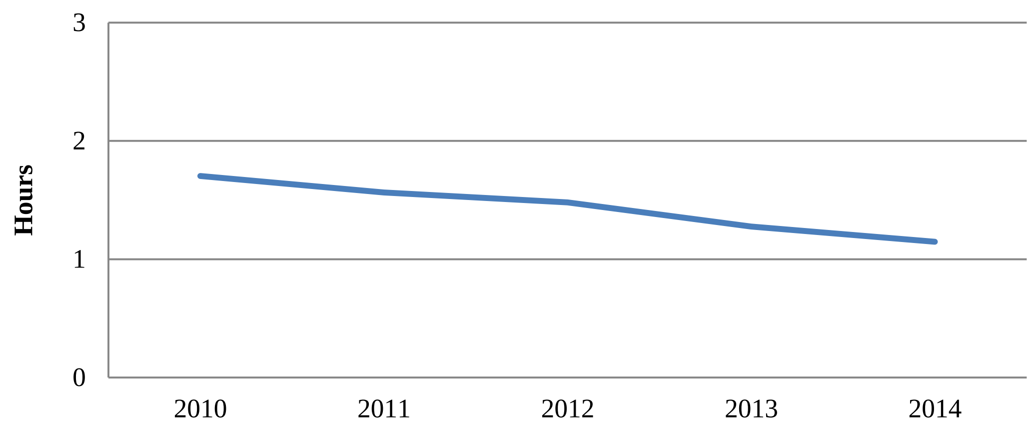
Between 2010 and 2014, the number of scheduled outages on Newfoundland Power's electrical system was reduced by approximately 20%.[16]

Outage Response: 2010 to 2014

The customer average interruption duration index ("CAIDI") measures the average outage duration that customers experience.[17] CAIDI is a measure of the average time it takes to restore service to a customer following an outage.

Chart 3-9 shows the CAIDI experienced by Newfoundland Power's customers, excluding significant events, during the period 2010 through 2014.

Chart 3-9: CAIDI
Newfoundland Power
(excl. significant events)
2010 to 2014



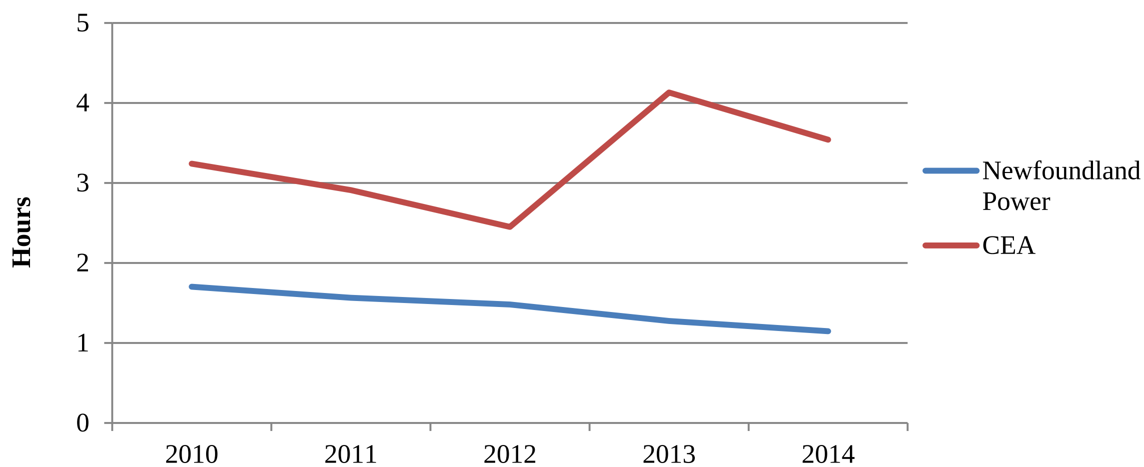
[16] In 2010, Newfoundland Power recorded 1,329 scheduled outages on its electrical system; in 2014, there were 1,066. (1,066 – 1,329 = -263. -263/1,329 = -0.198).

[17] In arithmetic terms, CAIDI is expressed as SAIDI/SAIFI.

Between 2010 and 2014, the average time it took to restore service to a Newfoundland Power customer was reduced from 1.7 hours to 1.15 hours, which represents a reduction of approximately 32%.

Chart 3-10 compares CAIDI for Newfoundland Power to the Canadian average for the period 2010 through 2014, excluding significant events.[18]

Chart 3-10: CAIDI
Newfoundland Power vs. Canadian Average
(excluding significant events)
2010 to 2014



Excluding significant events, the average time it took Newfoundland Power to restore service to customers following an outage during the period 2010 through 2014 was approximately 1.44 hours.[19] For the same period, the Canadian average was approximately 3.25 hours.[20] In 2014,

[18] See footnote 5.
[19] For 2010 through 2014, the average response times were 1.70, 1.56, 1.48, 1.28 and 1.15 hours, respectively.
[20] For 2010 through 2014, the average response times were 3.24, 2.91, 2.45, 4.13 and 3.54 hours, respectively.

Newfoundland Power's response time following a customer outage was approximately ⅓ the Canadian average.[21]

3.3.3 Operations Outlook

Newfoundland Power is taking further steps to improve the quality, efficiency and reliability of the electrical service it provides its customers.

These steps include implementation of technology to more efficiently schedule and dispatch work across the Company's service territory. For example, in 2013, Newfoundland Power implemented an automatic vehicle location ("AVL") system for its line trucks. The AVL system provides real-time information on the location of the Company's line crews. In 2014, the Company introduced centralized automated scheduling and dispatch for line work throughout its service territory. Together, these systems effectively replaced manual workflow management processes and permit greater optimization of daily crew schedules.

Improved scheduling and dispatching of work enables Newfoundland Power to improve the timeliness of the service it delivers to its customers. Examples of this include faster provision of new service connections to customers and quicker response to customer outages.[22]

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[21] 1.15/3.54 = 0.325.

[22] Since 2012, the Company has targeted 10 business days from receipt of electrical authorization for installation of new service connections.

Table 3-2 shows the percentage of new service connections that the Company has completed within 10 business days from 2012 to September 2015.[23]

Table 3-2
Customer Service Connections
10 Business Days (%)
2012 to 2015

2012	2013	2014	2015 (Sept.)
76	79	83	85

More efficient scheduling and dispatching of work also reduces the duration of outages experienced by Newfoundland Power's customers. Response to customer outages typically involves an element of travel. Real-time information on line crew locations helps ensure that the nearest available crew is dispatched to respond to a customer outage. This reduces travel time. Reduced travel time directly shortens the time a customer is without service. Reduced travel time also decreases the cost of responding to customers' needs.[24]

In 2013, Newfoundland Power commenced implementation of a geographic information system ("GIS") to record the location of its electrical equipment and system assets. This implementation is expected to be complete in 2016.[25] The GIS will be fully integrated with the Company's replacement SCADA system which is expected to be installed in 2016.[26] By 2017, the Company

[23] The Company records the number of days it takes to provide new customer service connections from the date of receipt of the connection authorization from the appropriate local electrical standards authority.
[24] A line crew and truck responding to a customer outage on overtime costs approximately $210/hr.
[25] The Company's GIS implementation project is described in *6.5 Geographical Information System Improvements* filed with Newfoundland Power's *2015 Capital Budget Application*.
[26] The Company's SCADA and GIS integration project is described in *6.4 SCADA System Replacement* filed with Newfoundland Power's *2015 Capital Budget Application*.

expects to commence replacement of its outage management system ("OMS") with a commercially available OMS.[27]

Once the GIS, SCADA system and OMS are fully implemented, Newfoundland Power will have enhanced capabilities to more cost effectively manage the electrical system on an ongoing basis. This will include the capability of Newfoundland Power's systems to isolate the source of customer outages through analysis of incoming customer notifications. This will enable speedier Company response.[28] These systems will also provide enhanced capability to notify individual customers of the status of the Company's restoration efforts. This includes outage response and information on the expected time of service restoration.[29]

Finally, these systems should improve the Company's ability to respond more effectively and efficiently to system emergencies.[30]

3.4 EMERGENCY PREPAREDNESS

Newfoundland Power has established emergency management practices for the severe weather events which affect its service territory. These practices have enabled reasonable restoration of service to customers following major weather events such as ice storms and hurricanes. The Company's emergency management practices have historically been effective.

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[27] The current plan for OMS replacement is described in *6.4 Outage Management System Replacement* filed with Newfoundland Power's *2016 Capital Budget Application*.

[28] This effectively results from the systems' capabilities to (i) group incoming customer outage notifications geographically, (ii) associate the notifications' source with the nearest common piece of electrical equipment and (iii) inform the line crew dispatched to respond to the outage of the likely equipment failure responsible.

[29] The Company currently has implemented SMS service for customer outage alerts. The enhanced notification capabilities will result from the predictive analysis described in the previous footnote.

[30] The Board's consultant, The Liberty Consulting Group, in its *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System* has concluded that while the Company's current OMS has served adequately, the Company's planned replacement is appropriate. See *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*, December 17, 2014, pages 69-73.

In both 2013 and 2014, unavailability of generation resources from Hydro resulted in significant outages for the customers of Newfoundland Power. There was nothing that the Company could do to prevent these events.[31] However, Newfoundland Power's response capabilities to such events were, and likely will continue to be, tested through the 2016/2017 test period.[32]

Newfoundland Power has taken steps to improve the resilience of its electrical system. In 2014, the Company installed additional distribution feeder automation, switching and reclosing facilities on the electrical system.[33] These improvements, which are consistent with utility best practice, contribute to enhanced emergency response capabilities.[34] Further automation is expected to contribute to improved system resilience over the 2016/2017 test period.

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[31] Following extensive review of these electrical system events, the Board's consultant, The Liberty Consulting Group, did not find that Newfoundland Power's operations or conditions contributed to the outages experienced by customers. See The Liberty Consulting Group's *Final Report addressing Newfoundland Power* of December 17, 2014, page 3.

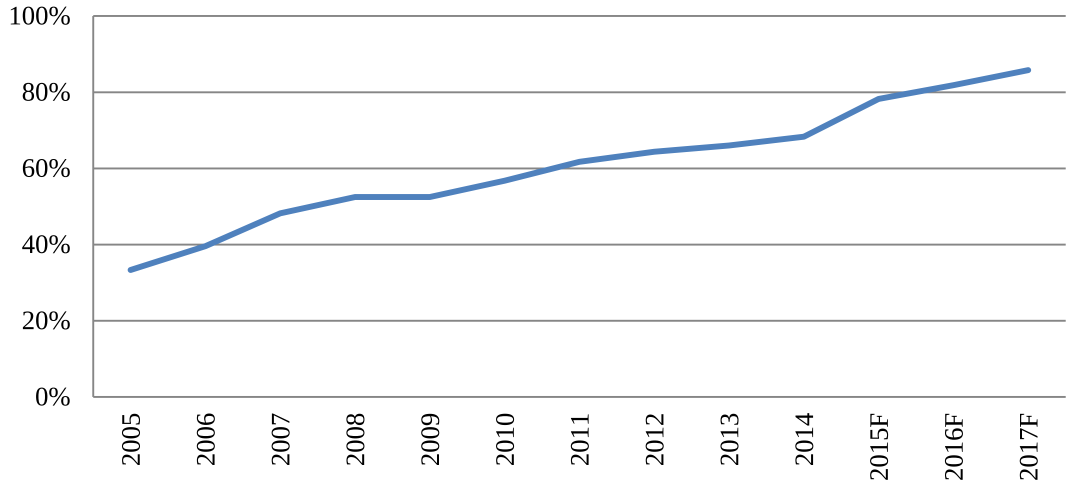
[32] The Board's consultant, The Liberty Consulting Group, found in its *Interim Report* of April 24, 2014 that "…..a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons." These findings were essentially confirmed in The Liberty Consulting Group's *Final Report addressing Newfoundland and Labrador Hydro* of December 17, 2014.

[33] These system improvements were approved by the Board in Order No. P.U. 14 (2014).

[34] See, for example, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, Priority 5: Deploy Advanced Control Capabilities*, Executive Office of the President, August 2013, page 16.

Chart 3-11 shows the percentage of Newfoundland Power's automated distribution feeders by year for the period 2005 through 2017F.

Chart 3-11: Automated Distribution Feeders
Newfoundland Power
2005 to 2017F



From 2014 through 2017, Newfoundland Power expects its percentage of automated distribution feeders to increase from 68% to 86%. All the Company's distribution feeders are expected to be automated by 2019.[35]

Increased feeder automation allows the Company to operate more of the electrical system remotely from the Company's System Control Centre. This enhances Newfoundland Power's flexibility in electrical operations in all system conditions, including emergency circumstances.

[35] For example, see *2.1: 2015 Substation Refurbishment and Modernization*, June 2014 filed with Newfoundland Power's *2015 Capital Budget Application*, which outlined plans to accelerate substation feeder automation so all feeders will be automated within 5 years.

The level of feeder automation was identified by the Company as a limitation in the response to the January 2014 system events.[36]

Increased use of downline distribution reclosers is also expected to continue through the 2016/2017 test period.[37] The installation of reclosers on larger distribution feeders enables the Company to isolate sections of those distribution feeders remotely. Like increased feeder automation, increased numbers of downline reclosers enhance operational flexibility in all system conditions, including emergency circumstances.[38] The lack of downline reclosing capability on large feeders was also identified by Newfoundland Power as a limitation in the response to the January 2014 system events.[39]

Newfoundland Power's emergency management practices have been adapted to permit the Company to better respond to any emergency circumstances that may present themselves. This includes possible future supply shortages.

Improved Newfoundland Power emergency management practices will not, however, be a substitute for inadequate generation resources.

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[36] See, for example, Newfoundland Power's *Interim Report*, March 24th, 2014, in the Board's *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System*, page 60.

[37] See, for example, Newfoundland Power's *2016 Capital Budget Application*, Schedule B, page 54 of 98, where plans to install 8 downline reclosers on distribution feeders are described.

[38] The benefit of reclosers installed on larger Newfoundland Power distribution feeders was shown in the response to system events which presented themselves on March 4th, 2015. During the morning of March 4th, 2015, the Company was able to rotate certain feeders which were not included in rotating power outages during the period January 2-8, 2014 due to the effects of cold load pickup.

[39] See, for example, Newfoundland Power's *Interim Report*, March 24th, 2014, in the Board's *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System*, page 60.

3.5 2016 AND 2017 OPERATING AND CAPITAL COSTS

3.5.1 Operating Costs

General

Gross operating costs represent approximately 9% of Newfoundland Power's forecast 2016 and 2017 revenue requirement.[40] Gross operating costs are those costs over which Newfoundland Power management has the greatest degree of control.

Table 3-3 shows Newfoundland Power's gross operating costs from 2013 to 2017F.

Table 3-3
Gross Operating Costs
2013 to 2017F
($000s)

2013	2014	2015F	2016F	2017F
56,466	59,623	57,476	59,755	60,104

Total gross operating costs for 2017 are forecast to increase by approximately 6.4% over 2013. This represents an annual increase in operating costs of approximately 1.6%, or $900,000, per year.

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

[40] See *Exhibit 7* in *Volume 2, Exhibits & Supporting Materials*. For 2016: $58,523,000/$669,685,000 = 0.087. For 2017: $60,170,000/$682,578,000 = 0.088.

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, in *Volume 2, Exhibits & Supporting Materials,* show the Company's gross operating costs from 2013 to 2017F by function and by breakdown, respectively.

Operating Costs by Function

Table 3-4 summarizes Newfoundland Power's operating costs by 3 functional categories: electricity supply, customer services and general for 2013 to 2017F.

Table 3-4
Operating Costs by Function
2013 to 2017F
($000s)

Function	**2013**	**2014**	**2015F**	**2016F**	**2017F**
Electricity Supply	26,072	27,817	26,112	26,961	27,575
Customer Services	11,072	12,042	11,108	11,449	11,271
General	19,322	19,764	20,256	21,345	21,258
Total	**56,466**	**59,623**	**57,476**	**59,755**	**60,104**

Table 3-5 shows operating costs associated with the electricity supply category broken out by function for 2013 to 2017F.

Table 3-5
Operating Costs – Electricity Supply
2013 to 2017F
($000s)

Function	**2013**	**2014**	**2015F**	**2016F**	**2017F**
Distribution	9,226	8,994	8,668	9,053	9,321
Transmission	928	1,289	1,025	1,050	1,075
Substations	2,629	2,627	2,624	2,734	2,814
Power Produced	2,877	2,985	2,918	3,038	3,125
Administration & Engineering	6,866	8,248	7,370	7,696	7,922
Telecommunications	1,418	1,552	1,438	1,370	1,399
Environment	243	210	288	292	300
Fleet Operations & Maintenance	1,885	1,912	1,781	1,728	1,619
Total	**26,072**	**27,817**	**26,112**	**26,961**	**27,575**

Electricity supply costs for 2017 are forecast to increase by 5.8%, or approximately $1.5 million, compared to 2013.

Electricity supply costs include electrical system operating maintenance activity. Labour rate increases impact the costs in this function.[41] A significant portion of the costs of response to electrical system events are also reflected in electricity supply costs.[42] Reduced Fleet Operations & Maintenance costs reflect (i) lower fuel costs and (ii) a reduction in vehicle costs resulting from AMR. Reduced Telecommunications costs reflect a combination of reduced 3rd party

[41] Electricity supply labour is forecast to increase from $15.8 million in 2013 to $17.3 million in 2017, or approximately 9.8% over the 4 year period, or 2.4% per year. This compares to a weighted labour cost increase of approximately 3.6% over the period. See footnote 50.

[42] The additional electricity supply costs necessary to respond to the supply outages of January 2014 are primarily reflected in the approximately $1.4 million increase in Administrative & Engineering Support costs in 2014 over 2013. Further costs necessary to respond to this event are reflected in Customer Services costs.

telecommunications service provider costs and increased stress testing costs for customer facing communication systems.[43]

Table 3-6 shows costs associated with the customer services category broken out by function for 2013 to 2017F.

Table 3-6
Operating Costs – Customer Services
2013 to 2017F
($000s)

Function	**2013**	**2014**	**2015F**	**2016F**	**2017F**
Customer Services	9,458	9,750	9,041	9,344	9,115
Conservation	717	802	767	778	801
Uncollectable Bills	897	1,490	1,300	1,327	1,355
Customer Services	**11,072**	**12,042**	**11,108**	**11,449**	**11,271**

Customer services operating costs for 2017 are forecast to increase by 1.8%, or approximately $200,000, compared to 2013.

This substantially reflects the combined effect of the (i) reduction in Customer Services costs resulting from AMR meter reading and (ii) an increase in Uncollectable Bills.[44]

[43] Newfoundland Power is forecasting a reduction in 3rd party telecommunication service provider costs of approximately $140,000 per year as a result of implementation of voice over internet protocol (“VOIP”) to replace existing telephone service in 2015 and 2016. The Company expects to incur approximately $40,000 per year in additional costs to stress test its IVR telephone system and website to ensure continuing resilience of these key customer communications facilities. Stress testing these systems was a recommendation arising from the Board’s *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System*. See The Liberty Consulting Group’s *Interim Report*, April 24, 2014, page 72.

[44] Changes in costs in this category are considered in detail in *Section 2.2.3: Balancing Costs & Service*.

Table 3-7 shows costs associated with the general category broken out by function from 2013 to 2017F.

Table 3-7
Operating Costs – General
2013 to 2017F
($000s)

	2013	2014	2015F	2016F	2017F
Information Services	3,175	3,370	3,601	3,891	4,031
Financial Services	1,707	1,751	1,821	1,885	1,944
Corporate & Employee Services	13,243	13,400	13,585	14,311	13,999
Insurances	1,197	1,243	1,249	1,258	1,284
Total	**19,322**	**19,764**	**20,256**	**21,345**	**21,258**

General operating costs are forecast to increase by 10.0%, or approximately $1.9 million, from 2013 to 2017.

Information Services costs are forecast to increase by $856,000 from 2013 to 2017. Over $500,000 of this is attributable to increases in 3rd party software licensing costs associated with the Company's information systems.[45] Increases in Corporate & Employee Services costs

[45] Over $200,000 of the increase relates to increased fees related to customer service technology, including the IVR telephone response system, e-mail management software, the SMS outage notification system and a proposed customer app. Over $100,000 of the increase relates to increased license and maintenance fees associated with supporting the Company's *Microsoft* Windows based operating systems. Approximately $100,000 of the increase relates to increased license and maintenance fees required to support increased field mobility in Newfoundland Power's operations, including GIS and scheduling and dispatching systems. Approximately $70,000 of the increase relates to cyber security systems.

include increased regulatory costs.[46]

Operating Costs by Breakdown

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

Table 3-8 shows the breakdown of operating costs from 2013 to 2017F.

Table 3-8
Operating Costs by Breakdown
2013 to 2017F
($000s)

	2013	**2014**	**2015F**	**2016F**	**2017F**
Labour	33,904	35,509	33,897	35,115	35,749
Other	22,562	24,114	23,579	24,640	24,355
Total	**56,466**	**59,623**	**57,476**	**59,755**	**60,104**

In 2016 and 2017, other costs are forecast to be approximately 40% of the Company's operating costs. Other costs include the cost of goods and services which the Company acquires from 3rd parties to provide service to its customers. These goods and services are typically acquired by competitive processes to ensure they are consistent with the least cost principle. Year over year

[46] Increased regulatory costs are attributable to a general increase in regulatory activity. Part of this is Board costs which increased by almost 14% from approximately $860,000 in 2013 to approximately $980,000 in 2015. The current level of regulatory activity is not expected to materially decrease through 2017 due to ongoing proceedings (i.e., the current Hydro GRA, the Board's ongoing *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System* and this Newfoundland Power GRA) and proceedings associated with cost of service matters associated with the pending interconnection of the Island Interconnected System to the North American grid.

changes in Other costs typically reflect changes in Newfoundland Power requirements. For example, Other Company Fees range from approximately $1.8 million to $2.7 million over the 2013 to 2017 period. This variability reflects the anticipated regulatory calendar. Similarly, increases in Advertising costs reflect initiatives outlined in the *Five-Year Conservation Plan: 2016-2020*.[47] Increases in Computing Equipment & Software costs are attributable to increases in 3rd party software licensing costs.

Other costs are forecast to increase by approximately 7.9%, or approximately $1.8 million, from 2013 to 2017. This represents an annual increase of approximately 2.0%, or approximately $450,000, through the 4 year period.

In 2016 and 2017, labour costs are forecast to be approximately 60% of the Company's operating costs. This is consistent with recent experience. Operating labour costs are an indicator of management efficiency in Newfoundland Power's day to day operations.

Newfoundland Power's labour costs are forecast to increase by a total of approximately 5.4%, or approximately $1.8 million, from 2013 to 2017. This represents an annual increase of approximately 1.4%, or approximately $450,000, through the 4 year period.

[47] Advertising in 2016 and 2017 is increased by $88,000 and $90,000, respectively, on account of advertising associated with the educational initiative for mini-split heat pumps. *See Company Evidence, Section 2.3.2: Future Customer Conservation Programming*, page 2-17, footnote 45.

Table 3-9 shows the breakdown of labour costs from 2013 to 2017F.

Table 3-9
Labour Costs by Breakdown
2013 to 2017F
($000s)

	2013	**2014**	**2015F**	**2016F**	**2017F**
Regular & Standby	28,735	29,678	29,457	30,258	31,242
Temporary	2,554	2,437	1,998	2,040	1,599
Overtime	2,615	3,394	2,442	2,817	2,908
Total	**33,904**	**35,509**	**33,897**	**35,115**	**35,749**

Regular & Standby labour costs to 2017 are forecast to increase by approximately 8.7%, or approximately $2.5 million, from 2013 to 2017. This is an annual increase of approximately 2.2%, or approximately $625,000, through the 4 year period. This primarily reflects the impact of annual labour rate increases, offset by improved labour productivity.

Temporary labour costs to 2017 are forecast to decrease by approximately 39%, or approximately $1.0 million, from 2013 to 2017. This primarily reflects the impact of the Company's accelerated adoption of AMR.[48]

Overtime labour costs to 2017 are forecast to increase by approximately 11.2%, or approximately $293,000, from 2013 to 2017. This increase primarily reflects an increase in the amount of overtime required to respond to electrical system events.[49]

48 The reduction in Customer Services labour costs described in *Section 2.2.3: Balancing Costs & Service*, is substantially a reduction in Temporary labour.

49 This includes events such as the loss of supply which occurred in January 2014 but also includes increased overtime associated with routine response to customer outage calls.

Overall, Newfoundland Power's operating labour costs over the period from 2013 to 2017 show reasonable management efficiency. The forecast annual increase of approximately 1.4% per year through the period compares to an annual increase in the Company's weighted average labour cost of approximately 3.6%.[50] This implies an improvement in operating efficiency of approximately 2.2% per year.[51]

3.5.2 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.

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50 Weighted labour cost increases reflect a combination of collectively bargained base wage increases agreed to between the Company and its union and forecast progression increases in employees' wages as a result of experience. For example, apprentice Powerline Technicians' wages increase by a combination of the base wage increase and the apprentice's progression through the apprenticeship program. The weighted labour cost increases were 4.25% in 2014, 3.75% in 2015 and 3.25% for 2016 and 2017. The 3.25% increase includes a 2.5% negotiated increase and a 0.75% progression. This is an average annual increase of approximately 3.6% for the period 2014 to 2017.

51 3.6% - 1.4% = 2.2%.

Table 3-10 shows capital expenditures by asset class from 2013 to 2017F.[52]

Table 3-10
Capital Expenditures by Asset Class
2013 to 2017F
($000s)

	2013	**2014**	**2015F[53]**	**2016F[54]**	**2017F**
Generation	4,508	11,751	4,914	19,095	13,781
Substations	16,646	19,662	22,478	17,940	18,326
Transmission	5,444	5,536	5,731	6,067	8,039
Distribution	41,976	62,066	42,473	45,055	51,683
General Property	2,734	1,032	3,224	1,840	2,026
Transportation	3,220	2,872	2,917	3,258	3,330
Telecommunications	920	97	123	514	434
Information Systems	4,312	4,080	7,501	8,009	6,395
Total	**79,760**	**107,096**	**89,361**	**101,778**	**104,014**

Capital expenditures vary from 2013 to 2017F for a variety of reasons. The greatest degree of variability is found in the Company's capital expenditures in the Generation, Distribution and Information Systems asset classes.

Variability in Generation capital expenditures substantially reflects past, current and forecast projects to rehabilitate Newfoundland Power hydroelectric plants. In 2014, approximately $6.2 million was expended on the Heart's Content hydroelectric plant rehabilitation.[55] In 2015 and 2016, an estimated total of $15.9 million will be expended on the Pierre's Brook penstock, surge

[52] These expenditures do not include the allowance for unforeseen expenditures and general expenses capitalized ("GEC"). GEC is calculated by the methodology approved in Order No. P.U. 3 (1995-1996). Capital expenditures for 2013 and 2014 include $4.7 million and $2.1 million, respectively, in approved projects which were completed in a subsequent year.

[53] The Company's *2015 Capital Budget Application* was approved in Order No. P.U. 40 (2014).

[54] The Company's *2016 Capital Budget Application* was approved in Order No. P.U. 28 (2015).

[55] This project was approved in Order No. P.U. 27 (2013).

tank and plant controls.[56] In 2017 and 2018, the Company intends to purchase a mobile generator at an estimated cost of $9.2 million and refurbish electric equipment in the Tors Cove hydroelectric plant at an estimated cost of $3.7 million.[57]

Distribution capital expenditures for 2014 include approximately $13.4 million associated with the replacement of the Bell Island submarine cable.[58]

Information Systems capital expenditures are forecast to be higher in the period 2015 through 2017. These higher expenditures substantially reflect GIS development, SCADA system replacement and OMS replacement.[59]

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[56] This project was approved in Order No. P.U. 40 (2014).
[57] See *2016 Capital Plan*, pages 11-12 filed with Newfoundland Power's *2016 Capital Budget Application*.
[58] This project was approved in Order No. P.U. 43 (2013).
[59] GIS development costs were approved in Order No. P.U. 40 (2014); the SCADA system replacement was approved in Order No. P.U. 40 (2014) and the OMS replacement was approved in Order No. P.U. 28 (2015).

SECTION 4: FINANCE

4.1 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 2015 is expected to be consistent with the maintenance of its financial integrity. For 2016 and 2017, the Company's financial performance under existing customer rates is not expected to be consistent with the fair return standard.

A central issue in this Application is Newfoundland Power's cost of capital for 2016 and 2017. The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2016 and 2017 is 9.50% based upon a target common equity ratio of 45%.

A return of 9.50% upon a target common equity ratio of 45% is consistent with the continued maintenance of Newfoundland Power's financial integrity in current economic circumstances. These circumstances do not justify the adoption of an automatic adjustment formula to establish a fair return for Newfoundland Power beyond 2017.

Proposed regulatory amortizations of hearing costs and a forecast 2016 revenue shortfall of approximately $4.1 million are consistent with Board practice.

4.2 FINANCIAL PERFORMANCE: 2013 TO 2017

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

This section of the evidence reviews the Company's actual financial performance for 2013 and 2014 and its forecast financial performance for 2015, 2016 and 2017 under existing customer rates. For the period 2013 to 2015F, Newfoundland Power's financial performance will have been consistent with the continued financial integrity of the Company. For 2016 and 2017, however, forecast financial performance under existing customer rates will not be consistent with the continued maintenance of Newfoundland Power's long-term financial integrity.

Exhibit 3 in Volume 2, Exhibits & Supporting Materials, shows the detail of Newfoundland Power's actual financial performance for 2013 and 2014 and forecast financial performance for 2015, 2016 and 2017 based on existing customer rates.

Exhibit 5 in Volume 2, Exhibits & Supporting Materials, compares forecast financial performance for 2016 and 2017 based on existing customer rates and proposed rates which incorporate the proposals contained in this Application.

4.2.1 Revenue

Electricity Rate Revenue

Table 4-1 shows electricity sales and revenue from 2013 to 2017E.[1]

Table 4-1
Electricity Sales and Revenue
2013 to 2017E

	2013	**2014**	**2015F**	**2016E**	**2017E**
Electricity Sales					
Electricity Sales (GWh)	5,763	5,899	5,963	5,993	6,018
Sales Growth (%)	2.0	2.4	1.1	0.5	0.4
Electricity Revenue (000s)					
Revenue from Rates	586,904	619,504	639,673	661,775	665,246
Excess earnings	(68)	-	-	-	-
RSA Transfers	10,436	4,039	7,795	6,481	3,885
Total Electricity Revenue	**597,272**	**623,543**	**647,468**	**668,256**	**669,131**

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

Electricity sales growth in 2013 and 2014 was 2.0% and 2.4% respectively. Sales growth for 2015 is forecast to be 1.1%. Under existing customer rates, 2016 sales growth is forecast to be 0.5% and 2017 sales growth is forecast to be 0.4%. The reduction in forecast sales growth for

[1] The suffix 'E' indicates 'existing rates' in effect at the time of printing this Evidence.

the period 2015 through 2017 generally reflects the struggling economy in the province of Newfoundland and Labrador over the period.[2]

Forecast electricity sales and electricity revenue for 2015, 2016 and 2017 are based on the Company's August 2015 sales forecast.[3]

Other Revenue

Table 4-2 shows other revenue from 2013 to 2017E.

Table 4-2
Other Revenue
2013 to 2017E
($000s)

	2013	**2014**	**2015F**	**2016E**	**2017E**
Pole Attachment	1,525	1,687	1,705	1,722	1,761
Provisioning Work	1,039	1,080	729	698	688
Customer Account Interest	996	1,092	983	992	998
Interest on RSA	1,019	255	61	34	(63)
Wheeling Charges	672	696	705	696	685
Miscellaneous	2,194	760	728	700	701
Total	**7,445**	**5,570**	**4,911**	**4,842**	**4,770**

Other revenue in 2013 was approximately $7.4 million. This included higher interest on the Company's Rate Stabilization Account ("RSA") resulting from relatively high year end 2012

2 The economic outlook for Newfoundland and Labrador is more fully described in *Service Territory Economics* at page 4-23, *infra*.

3 The *Customer, Energy, and Demand Forecast* of August 2015 is found in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 4*.

RSA balances and proceeds from a disposition of property.[4]

Over the five year period ending in 2017, pole attachment revenue is expected to increase by approximately $240,000. This reflects increasing pole attachment rates paid by CATV operators.[5] Provisioning work performed by the Company for others is forecast to decline by approximately $350,000 over this period. This principally reflects a reduction in work performed on behalf of Bell in the Company's service territory.

Newfoundland Power's other revenue is forecast to be stable at approximately $4.8 million to $4.9 million per year from 2015 through 2017.

4.2.2 Power Supply

Table 4-3 shows power supply costs from 2013 to 2017E.

Table 4-3
Power Supply Costs
2013 to 2017E
($000s)

	2013	**2014**	**2015F**	**2016E**	**2017E**
Purchases from Hydro (Normalized)	392,928	404,550	425,670	449,006	450,829
Weather Normalization Reserve	(2,335)	(2,335)	(2,335)	-	-
Demand Management Incentive Account ("DMI")	(383)	628	-	-	-
Power Supply Costs	**390,210**	**402,843**	**423,335**	**449,006**	**450,829**

4 The March RSA balance for 2013 was approximately $17.1 million; this compares to average March balances from 2014 to 2017E of approximately $2.9 million. The net proceeds from the property disposition were approximately $1.4 million and are reflected under Miscellaneous in Table 4-2.

5 During the period 2013 to 2017, pole attachment rates for CATV operators are forecast to increase from $18.48 per attachment per year to $22.63. CATV revenues are shared between Bell and Newfoundland Power pursuant to the joint use agreement between the companies.

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

4.2.3 Depreciation

In Order No. P.U.13 (2013), the Board required Newfoundland Power to file its next depreciation study relating to plant in service as of December 31, 2014, with its next general rate application.[6] Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") have performed the depreciation study as required by the Board ("The 2014 Study").[7]

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6 See Order No. P.U. 13 (2013), page 59, lines 45-46.

7 The Gannett Fleming *2014 Depreciation Study* is found in *Volume 3, Expert Evidence & Studies, Tab 1*.

Table 4-4 shows a comparison of current depreciation rates approved by the Board in Order No. P.U.13 (2013) with those recommended by Gannett Fleming in the 2014 Study.[8]

Table 4-4
Comparative Depreciation Rates (%)
Current & 2014 Study

Function	**Current**	**2014 Study**
Hydro Production	2.49	2.47
Other Production	5.59	4.69
Substation	2.68	3.08
Transmission	3.27	3.08
Distribution	3.19	3.26
General		
Computer hardware	16.72	16.90
Computer software	9.19	9.05
Transportation	9.52	9.06
Other	2.98	2.93
Composite Rate	**3.42**	**3.42**

The composite rate of depreciation recommended by Gannett Fleming in the 2014 Study is the same as the current composite rate of depreciation used by Newfoundland Power. Changes in the individual depreciation rates for differing asset classes recommended in the 2014 Study results in increases in depreciation expense for 2016 and 2017.[9]

[8] See Order No. P.U. 13 (2013), page 59, lines 42-43.
[9] For 2016, the increase in depreciation expense is $901,000 and for 2017 the increase is $933,000.

Table 4-5 shows depreciation expense from 2013 to 2017E reflecting adoption of the results of the 2014 Study commencing in 2016.

Table 4-5
Depreciation Expense
2013 to 2017E
($000s)

	2013	**2014**	**2015F**	**2016E**	**2017E**
Depreciation[10]	46,964	49,288	51,941	55,535	58,573

Increases in annual depreciation expense over the period 2013 to 2017 are substantially the result of the Company's annual capital investment in its electrical system.

4.2.4 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.

[10] Effective January 1, 2016, depreciation expense reflects implementation of the depreciation rates reflected in the 2014 Study. These depreciation rates include recovery of an accumulated reserve variance of approximately $12.2 million over the average remaining service life of the affected asset classes as recommended in the 2014 Study. Recovery of the reserve variance on this basis is consistent with the amortized recovery approved by the Board in Order No. P.U.13 (2013), page 59, lines 38-40.

Table 4-6 shows employee future benefits expense from 2013 to 2017E.

Table 4-6
Employee Future Benefits Expense
2013 to 2017E
($000s)

	2013	**2014**	**2015F**	**2016E**	**2017E**
Pension Expense	14,744	13,276	17,715	13,404	9,600
OPEBs Expense	10,880	10,968	8,678	8,772	8,292
Total Expense	**25,624**	**24,244**	**26,393**	**22,176**	**17,892**

The Company expects total employee future benefits expense to decrease by approximately $7.7 million from 2013 to 2017.

Pensions

Newfoundland Power maintains both defined benefit and defined contribution pension plans.[11]

[11] Newfoundland Power's largest pension plan is its defined benefit pension plan which was created in 1984. There were 328 active employees participating in this plan as at December 31, 2014. In addition, at December 31, 2014 the defined benefit pension plan provided retirement income to a total of 718 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.

Table 4-7 shows the components of Newfoundland Power's pension expense from 2013 to 2017E.

Table 4-7
Pension Expense
2013 to 2017E
($000s)

	2013	**2014**	**2015F**	**2016E**	**2017E**
Defined Contribution Pension Plans	1,453	1,633	1,825	2,022	2,252
Defined Benefit Pension Plans	13,291	11,643	15,890	11,382	7,348
Total Expense	**14,744**	**13,276**	**17,715**	**13,404**	**9,600**

Defined contribution pension plan expense is forecast to increase by approximately $800,000 between 2013 and 2017. This increase reflects a combination of (i) an increasing number of participants in the Company's defined contribution pension plan and (ii) inflationary increases in pay.

Defined benefit pension plan expense is forecast to decrease by approximately $5.9 million between 2013 and 2017. The primary cause of the defined benefit pension plan expense variability is variation in the discount rate used to value the Company's defined benefit pension plan obligation to employees. A decrease from 5% to 4% in this discount rate was principally responsible for the increase in 2015 defined benefit pension plan expense.[12]

Defined benefit pension plan expense for 2016 and 2017, which is forecast to decline, is influenced by a combination of factors including (i) increases in plan assets due to increased

[12] The discount rate used to value defined benefit pension obligations is prescribed by accounting standards. For 2013, this rate was 4.4%; for 2014, 5%; and for 2015, 4%.

solvency payments[13], (ii) returns on plan assets to 2014[14], (iii) a stable forecast discount rate,[15] and (iv) an increase in the proportion of plan assets invested in fixed income instruments.[16]

OPEBs

Table 4-8 shows OPEBs expense from 2013 to 2017E

Table 4-8
OPEBs Expense
2013 to 2017E
($000s)

	2013	2014	2015F	2016E	2017E
OPEBs Expense	10,880	10,968	8,678	8,772	8,292

OPEBs expense is forecast to decrease by approximately $2.6 million between 2013 and 2017. Like defined benefit pension plan expense, OPEBs expense variability is subject to variation in the discount rate used to value the Company's OPEB obligations to employees.[17]

[13] 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 2015 increased based on solvency deficiencies identified in Defined Benefit Pension Plan Valuations dated December 31, 2011 and December 31, 2014. The solvency deficiencies are being funded by special solvency payments (inclusive of interest) of approximately $10.7 million annually through 2014 and $7.0 million in 2015. No solvency payments are required after 2015.

[14] In 2014, the return on defined benefit pension plan assets was 15.5%. For the previous 5 years (2009-2013), returns were 17.1%, 13.5%, 4.3%, 7.6% and 8.7%.

[15] For forecast 2016 and 2017 defined benefit pension obligation valuation, a forecast discount rate of 4% is used.

[16] Newfoundland Power's defined benefit pension plan has been closed to new entrants since 2004. At December 31, 2014, the plan had 1,086 members, 66% of which were already retired. Within 5 years, the proportion of retirees to total plan members is expected to increase to 75%. The large proportion of retired members supports a greater proportion of plan assets being invested in fixed income securities. The current defined benefit pension plan asset investment strategy is to increase the proportion of fixed income securities to 60% of plan assets by 2020.

[17] The discount rate used to value OPEBs obligations is prescribed by accounting standards. For 2013, this rate was 4.3%; for 2014, 4.9%; and for 2015, 4%.

OPEBs expense for 2016 and 2017 is principally influenced by (i) a reduction in claims cost experience with the Company's OPEBs plan and (ii) a stable forecast discount rate.[18]

4.2.5 Finance Charges

Table 4-9 shows average debt, finance charges and average cost of debt for 2013 to 2017E.[19]

Table 4-9
Finance Charges
2013 to 2017E

	2013	2014	2015F	2016E	2017E
Average Debt ($000s)	504,185	532,234	555,979	575,703	599,493
Finance Charges ($000s)	35,609	35,772	35,349	35,345	36,644
Average Cost of Debt (%)	7.06%	6.72%	6.36%	6.14%	6.11%

Newfoundland Power's average debt consists of First Mortgage sinking fund bonds ("First Mortgage Bonds") and amounts outstanding under bank credit facilities.[20] Increases in average debt through 2017 reflect investment in assets to provide service to customers.

Finance charges through the 2013 to 2017 period are relatively stable and forecast to increase by approximately $1 million.

The average cost of debt from 2013 to 2017 is forecast to decline. This principally reflects lower average coupon rates on the Company's First Mortgage Bonds.

[18] For forecast 2016 and 2017 OPEBs obligation valuation, a forecast discount rate of 4% is used.
[19] Table 4-9 shows regulated finance charges, which excludes interest on security deposits because it is not included in the determination of revenue requirement.
[20] At December 31, 2014, approximately $484 million in First Mortgage Bonds was outstanding. Newfoundland Power's bank credit facilities are comprised of a $100 million committed revolving term facility and a $20 million demand facility. The $100 million facility is committed through the 2016/2017 test period.

4.2.6 Income Taxes

Table 4-10 shows income taxes from 2013 to 2017E.

Table 4-10
Income Taxes
2013 to 2017E

	2013	2014	2015F	2016E	2017E
Income Taxes ($000s)	14,866	16,201	16,210	15,486	14,889
Effective Income Tax Rate (%)	27.83%	28.91%	28.68%	28.79%	29.14%

Newfoundland Power's effective income tax rate, which approximates the statutory corporate income tax rate of 29%, is forecast to remain stable through the 2013 to 2017 period.

4.2.7 Returns

Table 4-11 shows the 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 2013 to 2017E.

Table 4-11
Rates of Return
2013 to 2017E
(%)

	2013	2014	2015F	2016E	2017E
Return on Rate Base					
Midpoint (Approved)	7.92	7.88	7.50	-	-
Actual / Forecast	8.10	7.83	7.45	6.96	6.61
Return on Common Equity	9.16	9.15	8.82	7.96	7.22

Newfoundland Power's actual rate of return on rate base for 2013 was 0.18% above the mid-point used for rate setting purposes.[21] In 2014, the Company's actual return on rate base was 0.05% below the mid-point approved by the Board.[22] For 2015, the Company's return on rate base is forecast to be 0.05% below the mid-point approved by the Board.[23]

The forecast returns on rate base and equity for 2016 and 2017 are below the current ranges of ± 0.18% for rate base and the implied range of ± 0.40% for equity.[24] This reflects the eroding financial position of the Company which would result from the continuation of existing customer rates.

4.2.8 Credit Metrics

Table 4-12 shows Newfoundland Power's credit metrics from 2013 to 2017E under existing customer rates.

Table 4-12
Credit Metrics
2013 to 2017E

	2013	**2014**	**2015F**	**2016E**	**2017E**
Pre-tax Interest Coverage (times)	2.3	2.3	2.3	2.2	2.1
Cash Flow Interest Coverage (times)[25]	3.9	3.6	3.8	3.9	3.8
Cash Flow Debt Coverage (%)[26]	20.1	17.5	17.5	17.5	16.9

21 In 2013, Newfoundland Power recorded excess earnings of $68,000 (see Table 4-1).
22 See Order No. P.U. 23 (2013).
23 See Order No. P.U. 51 (2014).
24 See, for example, Order No. P.U. 19 (2003), page 76, where the Board noted that the implied range of return on regulated common equity was 81 basis points for 2003. This observed stability is substantially a reflection of the stable capital structure of Newfoundland Power over time.
25 2013 and 2014 cash flow metrics based on Moody's Investors Service methodology.
26 2013 and 2014 cash flow metrics based on Moody's Investors Service methodology.

Between 2013 and 2015, Newfoundland Power has maintained A credit ratings from Moody's Investor's Services ("Moody's") and DBRS Limited ("DBRS") on its First Mortgage Bonds.

Exhibit 4, in *Volume 2, Exhibits & Supporting Materials,* shows Newfoundland Power's current credit ratings from Moody's and DBRS.

As each of the current credit ratings from Moody's and DBRS indicates, Newfoundland Power's credit ratings are substantially influenced by factors other than credit metrics. For example, Moody's attributes 40% of its rating to financial metrics, including capital structure. By comparison, 50% of Moody's rating is attributable to regulatory considerations such as the regulatory framework (25%) and the ability to recover costs and earn returns (25%).[27] Similarly, DBRS considers Newfoundland Power's stable and supportive regulatory environment and strong financial profile as key credit strengths.[28]

Under existing customer rates, Newfoundland Power's pre-tax interest coverage is forecast to decline to 2.1 times in 2017. This has implications for Newfoundland Power's future financing flexibility.[29]

4.3 COST OF CAPITAL

In this Application, the Board will consider Newfoundland Power's cost of capital for 2016 and 2017. In addition, the Board will consider whether economic conditions support the use

[27] See *Exhibit 4* in *Volume 2 Exhibits & Supporting Materials, Moody's,* page 4.
[28] See *Exhibit 4* in *Volume 2, Exhibits & Supporting Materials, DBRS,* page 2.
[29] See *Section 4.3.4: Impact of Proposed Returns,* page 4-41.

of an automatic adjustment formula to annually adjust the return on rate base to reflect changes in the cost of equity for years following 2017.

The expert evidence filed with this Application indicates a fair return for Newfoundland Power for 2016 and 2017 reflects a return on equity of 9.5%, based upon a capital structure with a target equity ratio of 45%.

This section of the Company evidence summarizes the fair return standard as applied by the Board within the regulatory framework which exists in the province of Newfoundland and Labrador. For a return to be considered fair it must be (i) commensurate with return on investments of similar risk, (ii) sufficient to ensure financial integrity and (iii) sufficient to attract necessary capital.

This section of the evidence reviews the more prominent elements of risk to which Newfoundland Power, as a business, is exposed. This review indicates a more negative near-term local economic outlook and an increasingly uncertain power supply outlook when compared to 2012. Together, these contribute to an overall higher risk outlook than existed at the time of the Company's last general rate application.

This section of the evidence surveys actual long Canada bond yields since 2012 and current forecasts. Based upon this, Newfoundland Power concludes that current economic circumstances do not justify the adoption of an automatic adjustment formula to establish a fair return for Newfoundland Power beyond 2017.

Finally, this section of the evidence reviews Newfoundland Power's credit metrics under existing and proposed customer rates. Proposed customer rates, which include a return on equity of 9.5%, based upon a capital structure with a target equity ratio of 45%, are consistent with the fair return standard.

4.3.1 A Fair Return

Introduction

In regulatory practice, the fair return is the compensation to investors for investment of their funds to finance the utility's provision of service to customers.

The nature of utility investment tends to be long-term. For example, the utility investment in a distribution pole providing service to a residential subdivision will not be fully recovered for decades. Over that period, the cost of finance will represent a significant portion of the overall cost of that distribution pole. For this reason, fair returns, together with sound financial management, are essential to least cost service delivery to customers. The long-term nature of utility investment underscores the importance of stability and consistency in regulatory decision-making.

The determination of a fair return is a central responsibility for a regulator. The discharge of that responsibility is guided by a combination of the legislative framework governing utility regulation and accepted utility practice.

Regulatory Framework

The cornerstones of the legislative framework governing the regulation of Newfoundland Power are the *Public Utilities Act* and the *Electrical Power Control Act, 1994.* They provide essential guidance to the Board concerning the determination of a fair return for Newfoundland Power.

Section 80(1) of the *Public Utilities Act* provides that "A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board."

Section 3 of the *Electrical Power Control Act, 1994* outlines the power policy of the province. Key features of this policy are reasonable customer rates and efficient utility operations.[30] Section 3 of the *Electrical Power Control Act, 1994* specifically requires the Board to set customer rates that "…..provide sufficient revenue to the producer or retailer of the power 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."[31] In addition, Section 3 of the *Electrical Power Control Act, 1994* directs that customer rates should be established based on *forecast* costs wherever practicable.[32]

Insofar as it relates to returns, the legislative framework in Newfoundland and Labrador is substantially similar to that in other North American jurisdictions. In considering Section 80 of the *Public Utilities Act* and Section 3 of the *Electrical Power Control Act, 1994*, the Newfoundland and Labrador Court of Appeal has observed that:

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[30] Sections 3(a)(i) and 3(b), *Electrical Power Control Act, 1994*.
[31] Section 3(a)(iii), *Electrical Power Control Act, 1994*.
[32] Section 3(a)(ii), *Electrical Power Control Act, 1994*.

"[24]….the entitlement of the utility to a fair return on its investment is always regarded as of fundamental importance. In the United States, controls which fail to allow a fair return have the potential of running afoul of constitutional strictures against confiscation of property without due compensation. While the same constitutional concerns may not be present in Canada, the case law has at times nevertheless referred to the entitlement to a fair return as a 'common law right' which should be read into the legislation even where it is not specifically expressed.

[25] There is no uniform methodology employed in the regulatory jurisdictions in North America for the determination of a just and reasonable rate of return. What recurs, however, is a theme that the process is not an exact science and depends on a variety of factors necessary to balance the competing interests involved. Rate setting is essentially a prospective exercise where determinations are made on the basis of estimates and information that will not necessarily remain static."[33]

The prominence of risk in the context of the determination of a fair return has also been recognized by the Newfoundland and Labrador Court of Appeal:

"[31]…..because the setting of the rate of return is based on projections, one cannot be sure that the rate of return will be achieved in practice. Although the utility is 'entitled' by s. 80 of the Act to have the Board determine a just and reasonable rate of return based on appropriate predictive techniques and methodologies, it is not 'entitled', in the sense of being guaranteed, to the rate of return. The utility therefore takes the risk that its chosen management techniques and the future economic climate may not yield its expected success. Although some of the activities of the utility are regulated within the framework of the statutory objectives, the utility nevertheless remains subject to business risks and the effects of management decisions. To that extent, the financial risks associated with the operation of the utility, just as in the case of any private business, are to be born by the investors in the enterprise, not the consumer of the service."[34]

Regulatory Practice

A Fair Return

The Board's application of the statutory principles contained in the *Public Utilities Act* and the *Electrical Power Control Act, 1994* has been consistent with the application of accepted

[33] *The Stated Case*, June 15, 1998, Newfoundland and Labrador Court of Appeal, paragraphs 24-25.
[34] *The Stated Case*, June 15, 1998, Newfoundland and Labrador Court of Appeal, paragraph 31.

regulatory principles in Canada and the United States.[35] With respect to those principles, the Board has observed:

> "In addition to the statutory principles which guide the Board there are a number of well accepted principles of public utility regulation which are used to estimate the required rate of return. These principles have been endorsed not only by regulators but also by appellate courts in both Canada and the United States. A public utility must be able to assure financial integrity, so that it can maintain a sound credit rating and be able to attract additional capital when required. In order to maintain access to capital financing it must achieve earnings comparable to those of other companies with similar risk.…
>
> "…The Board is required not only to assess current return requirements but also to forecast what rate of return expectations and financial market conditions will be during the forecast period. Rates are set prospectively on the basis of forecast revenues and costs, including the cost of capital."[36]

The attributes of a fair utility return recognized by the Board have also reflected accepted regulatory principles in North America. The Board has repeatedly expressed those attributes as follows:

> "Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:
>
> - Commensurate with return on investments of similar risk;
> - Sufficient to ensure financial integrity; and
> - Sufficient to attract necessary capital
>
> The fair return principle is consistent with both Section 80(1) of the Act and Section 3(a)(iii) of the EPCA."[37]

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[35] This flows from the requirement in Section 4 of the *Electrical Power Control Act, 1994* that "In carrying out its duties and exercising its powers under this Act or under the Public Utilities Act, the public utilities board shall implement the power policy declared in section 3, and in doing so shall apply tests which are consistent with generally accepted sound public utility practice."

[36] Order No. P.U. 16 (1998-99), pages 9-10.

[37] Order No. P.U. 32 (2007), Appendix A, page 6. See also, Order No. P.U. 19 (2003), page 15; Order No. P.U. 43 (2009), page 11; and Order No. P.U. 13 (2013), page 12, lines 17-26.

Capital Structure

Newfoundland Power has maintained a stable capital structure for decades. The Board's evaluation of that capital structure has been consistent over this period.

The significance of capital structure in the determination of a fair return has been recognized by the Newfoundland and Labrador Court of Appeal. In addition, the Court has alluded to the importance of stability in capital structure management:

> "[134]…..the level of overall capitalization and the composition of the capital structure of a utility are both matters of regulatory concern, at least insofar as they affect the utility's rate of return on rate base and hence the cost to consumers of the delivery of reliable service…
>
> [135] In approaching these questions, it has to be remembered that there is no such thing as one ideal capital structure. It is a function of economic conditions, business risks and 'largely a matter of business judgement'. Furthermore, a given capital structure cannot be changed easily or quickly. As well, the long-term effects of changes on capital structure on the enterprise and on the future cost of capital may not be easily predictable."[38]

In 1990, the Board accepted a target common equity ratio of 42% - 47% in Newfoundland Power's capital structure as reasonable.[39] In 1991, the Board approved a common equity ratio of just over 45% with the understanding that the Company would bring it within the approved range of 40% - 45% by 1993.[40] Since 1996, the Board has repeatedly accepted that Newfoundland Power's capital structure, with a target 45% common equity, was reasonable for the purposes of setting customer rates.[41]

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[38] *The Stated Case*, June 15, 1998, Newfoundland and Labrador Court of Appeal, paragraphs 134-135.
[39] Order No. P.U. 1 (1990).
[40] Order No. P.U. 6 (1991).
[41] See Order Nos. P.U. 7 (1996-97), P.U. 16 (1998-99), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009) and P.U. 13 (2013).

The justification for the Board's acceptance of the longstanding equity component for Newfoundland Power has also been consistent. In Order No. P.U. 19 (2003), the Board observed:

> "The capital structure of NP has been maintained through the ongoing decisions of the Board as contained in its respective Orders and also NP's actions in managing the level of common equity accordingly. Generally in the past it has been determined by the Board that a strong equity component is needed to mitigate the impact of NP's relatively small size and low growth potential."[42]

In considering an appropriate capital structure for Newfoundland Power in 2003, the Board characterized Newfoundland Power's existing capital structure as a "…sound and successful…" one.

This capital structure has historically been viewed by credit rating agencies as a credit strength.[43]

4.3.2 Risk Assessment

Introduction

Newfoundland Power's cost of capital is that rate of return investors could expect to earn if they invested in equally risky securities.[44] In regulatory practice, the opportunity cost of capital is integral to the concept of a fair return. So, cost of capital is essentially a relative concept. The accepted relative measure for determining a business' cost of capital is risk.

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[42] Order No. P.U. 19 (2003), page 45.

[43] See, for example, *Exhibit 4* in *Volume 2, Exhibits & Supporting Materials*, *DBRS Rating Report*, August 21, 2015, page 2 and Moody's Investor's Service, *Credit Opinion*, January 19, 2015, page 2.

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

Risk is an assessment of the capability of an enterprise to recover its investment as well as earn a return on that investment. Relative to its Canadian utility peers, the Board has historically assessed Newfoundland Power to be an average risk Canadian utility.[45] Newfoundland Power's capital structure has been part and parcel of that assessment.[46]

The principal risks to which Newfoundland Power is exposed have not changed materially over time. For example, forecast economic conditions in the Company's service territory are always a risk to be evaluated in determining the cost of capital. However, the degree of exposure related to each element of risk can change and impact the forecast cost of capital. Differences between a robust economic outlook and a more depressed one can, for example, be a factor in the determination of the cost of capital. For this reason, the Board assesses these risks in every rate case.

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

Service Territory Economics

Over the past decade, the economy of Newfoundland and Labrador experienced significant growth. For much of this period, the provincial economy led the country in growth.

[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 Nos. P.U. 43 (2009), page 13 and P.U. 13 (2013), page 17, lines 19-20, where the Board found that Newfoundland Power continued to be an average risk Canadian utility.

[46] See, for example, Order No. P.U. 13 (2013), page 16, line 1 to page 17, line 23. In the Company's 2008 and 2010 General Rate Applications, the Company's capital structure was agreed with intervenors and approved as appropriate by the Board. See Order No. P.U. 43 (2009), page 10, lines 8-22 and Order No. P.U. 32 (2007), page 24.

The economy in Newfoundland and Labrador is expected to struggle over the 2016/2017 test period and beyond. In its *Summer 2015 Provincial Outlook*, The Conference Board of Canada indicated:

> "Newfoundland and Labrador's economy is not doing well. All key economic indicators are down in the first half of the year and weakness in the economy will persist for the next few years."[47]

This general view is echoed by the provincial government which has indicated the province has entered a period of economic contraction and that growth is not expected to resume until 2019. The primary cause of the relatively weak short-term economic outlook is weaker commodity markets. Prices for both oil and iron ore, key provincial exports, have declined. This, in turn, has resulted in reduced employment and delays in resource development.[48]

Newfoundland and Labrador's short-term economic outlook is the most negative in a decade. It is materially reduced from the economic outlook in 2012 when the Company filed its last general rate application.

The longer-term economic outlook for Newfoundland and Labrador is also relatively weak. Over the 20 year period ending in 2035, The Conference Board of Canada is forecasting that the economy of Newfoundland and Labrador will grow at an annual average compound rate of

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[47] See *Customer Energy and Demand Forecast, Attachment A* in *Volume 2, Exhibits and Supporting Materials, Reports, Tab 4,* page 3.

[48] See *The Economy 2015*, Economic Research and Analysis Division, Department of Finance, pages 12-15.

0.9%.[49] This is forecast to be the lowest average annual growth rate of Canadian provincial economies.[50]

The Conference Board of Canada has indicated that a primary contributor to Newfoundland and Labrador's relatively weak forecast long-term economic performance is demographic:

> "The key factors influencing the long-term performance of the provincial economies will be population growth, labour force productivity, and investment patterns. Population growth will vary considerably from province to province, although all provinces will be dealing with a declining natural rate of increase. Moreover, even though significant advances in communication technology have lessened the importance of location for many industries, the overall movement of the population within and between provinces is expected to continue to be one in which people move from smaller to larger centres – and net international migration will favour the larger provinces. These trends will result in declining populations and a faster aging of the population in two Atlantic provinces – Newfoundland and Labrador, and New Brunswick. This profound demographic change will mean fewer people of working age and, therefore, weaker economic growth. Even if stronger productivity gains mitigate the demographic effects on real GDP growth, real economic growth in Atlantic provinces over the 2015-35 period will be modest. However, those productivity gains should allow at least some growth in real GDP per capita to continue, albeit at a slower pace, over the next 20 years."[51]

Demographics, including a declining and aging population, are expected to contribute to the province having the lowest average growth rate of any provincial economy over the longer-term. This can be expected to present challenges to the Company's ability to recover its investment in long-life utility assets and earn a fair return.

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[49] *Provincial Outlook 2015, Long-Term Economic Forecast*, The Conference Board of Canada, Chapter 1, page 1.

[50] *Provincial Outlook 2015, Long-Term Economic Forecast*, The Conference Board of Canada, page iii.

[51] *Provincial Outlook 2015, Long-Term Economic Forecast*, The Conference Board of Canada, page iii-iv.

Service Territory Demographics

The demographic outlook for Newfoundland Power's service territory indicates that population is in decline. Newfoundland and Labrador's population is expected to decline by approximately 1% from 2015 through 2017.[52] Through 2035, the decline in population is expected to be more than 4%.[53]

The declining population in Newfoundland and Labrador is accompanied by increased migration from rural to urban areas. The 2011 Canadian census showed that almost 90% of the communities in Newfoundland Power's service territory that had a population of less than 1,000 people experienced a decline in population in the prior 10 year period.[54]

The combination of a forecast decline in population and urban migration has potential consequences for future investment recovery for Newfoundland Power.

In the 15 years to 2014, Newfoundland and Labrador's population declined by a total of 1%.[55] Over this 15 year period, 21% of the communities in Newfoundland Power's service territory with a population of less than 1,000 people experienced a decline in the number of customers. In 2014, approximately 38% of the Company's distribution plant served customers in communities

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52 For 2015, 2016 and 2017, the population is expected to decline by 0.2%, 0.4% and 0.4%, respectively. See *The Economy 2015,* Economic Research and Analysis Division, Department of Finance, Government of Newfoundland and Labrador, page 13.

53 See *Provincial Outlook 2015*, *Long Term Economic Forecast*, The Conference Board of Canada, page 1, where it is indicated that Newfoundland and Labrador's population is forecast to decline by approximately 4.4 % through 2035.

54 133 of the 188 municipalities that Newfoundland Power serves had a population of less than 1,000 in 2011. Of these 133 municipalities, 118 experience a decline in population from 2001 to 2011 (118/133 = 0.89, or 89%).

55 *Table 051-0005 – Estimates of Population, Canada, provinces and territories, quarterly (persons),* Statistics Canada.

of less than 1,000 people; customers in these communities accounted for only 14% of Newfoundland Power's total customer base.

The implications of the combination of a forecast decline in population and urban migration are clear. The costs of serving a declining number of customers, in smaller rural settings, will put increased pressure on the ability of the Company to recover the disproportionate investment in assets required to serve those customers.[56]

Power Supply

Newfoundland Power is practically dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers. Currently, Newfoundland Power purchases approximately 93% of its power supply requirements from Hydro. These power purchases are Newfoundland Power's largest cost. In 2014, Newfoundland Power's power purchases from Hydro cost approximately $403 million, or approximately 64% of total revenue.[57]

By virtue of legislative amendments made late in 2012, Hydro was granted the exclusive right to sell electrical power or energy to Newfoundland Power and industrial customers on the island of Newfoundland.[58] These amendments were made to facilitate the development of Nalcor Energy's 824 MW Muskrat Falls hydroelectric generating plant and the ± 350 kV HVdc Labrador-Island transmission link. Once complete, the development will result in an

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[56] The provincial power policy requires that utility facilities be managed and operated in a manner that results in consumers in the province having equitable access to an adequate supply of power. See the *Electrical Power Control Act, 1994*, Section 3(b)(ii).

[57] In 2004, Newfoundland Power's power purchases from Hydro totaled approximately $244 million.

[58] See S.N.L. 2012, Ch. 47, Section 3, assented to December 22, 2012.

interconnection of the island electrical system to the North American grid.[59] The interconnection was originally expected to be complete in mid-2018, however, this schedule is substantially under review.[60]

This development will be a primary source of any additional power supply requirements for Newfoundland Power. In addition, Muskrat Falls is expected to displace the current production of Hydro's Holyrood thermal generating plant when the latter is expected to be decommissioned in 5 years or so. The Holyrood thermal generating plant is located approximately 40 km from Newfoundland Power's primary load centre on the northeast Avalon Peninsula.

The current total estimated cost of the Muskrat Falls and Labrador-Island transmission link is approximately \$9.05 billion.[61] This is approximately 3 times the total book value of current utility investment of Hydro and Newfoundland Power combined.[62]

The size of the investment in Muskrat Falls and the Labrador-Island transmission link is large compared to the existing electrical system serving the island of Newfoundland. This indicates that material increases in Newfoundland Power's cost of power supply are likely. The size of

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[59] A third component of the interconnection is the ± 200 kV HVdc Maritime link which will provide a transmission interconnection between Nova Scotia and the southwestern portion of the island of Newfoundland. This component is being constructed by Emera Inc..

[60] See *Muskrat Falls Project Oversight Committee*, Committee Report, August 2015, page 23.

[61] This includes construction costs of \$7.65 billion and financing costs of \$1.4 billion. See *Muskrat Falls Project Oversight Committee*, Committee Report, August 2015, page 2.

[62] For Hydro's total rate base of approximately \$1.8 billion, see *Exhibit 13: 2015 Test Year Cost of Service* filed in Hydro's 2013 Amended General Rate Application. For Newfoundland Power's total rate base of approximately \$0.965 billion, see Newfoundland Power *2014 Annual Return* (filed pursuant to ss. 59 (2) of the *Public Utilities Act*), Return 3. (\$1.8 billion + \$0.965 billion = \$2.765 billion. \$2.765 billion x 3 = \$8.295 billion).

those increases is currently uncertain.[63]

Cost uncertainty in Newfoundland Power's power supply outlook has long-term implications for the Company. One such potential implication for debt investors has been identified by Moody's. In its January 19, 2015 *Credit Opinion on Newfoundland Power*, Moody's expressed:

> "…..a cautionary note related to our concern that the utility's future ability to fully recover costs and earn returns may be compromised as the Province of Newfoundland and Labrador undertakes development of the Muskrat Falls hydroelectric project on the lower Churchill river and the related transmission infrastructure. This politically charged project is large relative to the provincial economy and is expected to place considerable upward pressure on future electricity rates."[64]

Large increases in Newfoundland Power's cost of power supply could also affect the markets the Company serves. Currently, approximately 49% of Newfoundland Power's sales are to space and water heating markets.[65] Higher supply prices could subject those markets to possible competition. This would be dependent upon the comparative price of competing heating sources.[66]

The development of Muskrat Falls and the interconnection of the island electrical system to the North American grid creates other uncertainties with respect to Newfoundland Power's future

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[63] The final costs will not be known until project completion, however, public indication is that the project will exceed budget and the schedule is under review. Nor is it certain how export sales from Muskrat Falls will be treated from a cost of service perspective. A proceeding to address cost of service implications of Muskrat Falls and the interconnection to the North American grid has not yet been scheduled but is expected to commence in 2016.

[64] See *Exhibit 4* in *Volume 2, Exhibits and Supporting Materials,* page 2.

[65] See sales to space and water heating markets derived from data developed for *Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015*, June 2015, ICF International.

[66] Newfoundland Power has not experienced significant competition for space and water heating since the 1990s when the primary competition was with furnace oil.

power supply. This includes the technical uncertainty related to interconnection to the North American grid.[67] It also includes the uncertainty related to supply reliability following the proposed decommissioning of the Holyrood thermal generating plant.[68] These uncertainties are expected to exist through the medium-term.

In each of January 2013 and January 2014, Newfoundland Power experienced substantial sustained interruption in its power supply from Hydro.[69] In January 2014, the Board initiated an investigation into the causes of these supply interruptions.[70] While the Board has not concluded its review of these supply interruptions, significant evidence indicates that higher risk of supply interruptions may exist until the commissioning of Muskrat Falls and the interconnection with the North American grid.[71] The extent of this heightened supply risk is uncertain. Nevertheless, the near-term risks associated with power supply reliability appear increased since the Company filed its last rate case in 2012.

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67 It appears that many of the operational and technical studies necessary to understand and develop operating guidelines associated with the interconnection to the North American grid are to be completed by Hydro or its affiliates in the 2015-2016 timeframe. See, for example, responses to Requests for Information PUB-NLH-241, PUB-NLH-445, PUB-NLH-486 and PUB-NLH-494 filed in the Board's *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System.*

68 Holyrood is approximately 40 km from Newfoundland Power's load centre on the northeast Avalon Peninsula. The Labrador Island transmission link will be required to traverse approximately 1,100 km to deliver power to the northeast Avalon Peninsula. This matter is currently being reviewed by the Board as part of Phase II of its *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System*.

69 Another significant interruption was experienced on March 4, 2015, however, the exact cause or causes of that interruption are under investigation by the Board and are currently uncertain.

70 The causes of these supply interruptions are the subject matter of Phase I of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*. The Board's final report on Phase I is currently outstanding.

71 The Board's consultant in its investigation, The Liberty Consulting Group, in their *Interim Report* of April 24, 2014 found the outages "…..stemmed from two differing sets of causes: (a) the insufficiency of generating resources to meet customer demands, and (b) issues with the operation of key transmission system equipment" and further that "…..a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons." These findings were essentially confirmed in The Liberty Consulting Group's *Final Report addressing Newfoundland and Labrador Hydro* of December 17, 2014.

Operating Conditions

Newfoundland Power is principally an electrical distribution utility. Typically, the vast majority of electrical system outages result from distribution failures.[72] Newfoundland Power also serves a substantial heating load. This makes the Company's response to failure particularly critical in the winter months.

Weather conditions are a leading cause of electrical distribution system failure in Canada. The climate across the Company's service territory includes the most severe wind and ice conditions in populated regions of Canada; outages arising from hurricanes, blizzards and freezing rain are relatively high risks in Newfoundland Power's service territory.[73]

The relatively severe weather conditions in Newfoundland Power's service territory increase the unpredictability of the Company's operating and capital costs.[74] This can result in earnings volatility.

[72] For example, Canadian Electricity Association, *Service Continuity Data Report on Distribution System Performance in Electric Utilities 2014*, indicates that approximately 89% of all customer outage duration results from electrical distribution failure. This has not been the case for Newfoundland Power's customers since 2013, as power supply shortages have made a disproportionately high contribution to overall customer outage duration since that time.

[73] Data for historic weather is available from Environment Canada, National Climate Data and Information Archive website, http://www.weatherstats.ca/winners.html?location=stjohns;category=1. For example, St. John's is the windiest city year-round in Canada. Similarly, Gander is the snowiest town in Canada with the most days of freezing rain.

[74] 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. In September 2012, Tropical Storm Leslie resulted in increased Company costs of approximately $1.6 million.

Cost Flexibility

Table 4-13 shows revenue and costs for Newfoundland Power on a kWh basis for 1994, 2004 and 2014.

Table 4-13
Revenue and Costs
1994, 2004 & 2014
(¢ per kWh)

	1994	**2004**	**2014**
Revenue	7.75	8.12	10.68
Energy Supply Costs	4.31	4.90	5.83
Fixed Costs[75]	1.79	1.65	3.20
Operating Costs	1.00	0.92	0.97
Operating Costs as % of Revenue	**13%**	**11%**	**9%**

Over the past 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 electrical system to serve customers. Energy supply costs and fixed costs, both of which have increased materially over the past 20 years, comprised approximately 85% of revenues on a kWh basis. These costs are substantially beyond management control in any given year.

Newfoundland Power's nominal operating costs have been stable on a kWh basis over the past 2 decades. This is reflective of sound cost management. However, the steady reduction of the *proportion* of operating costs to total costs on a kWh basis is reflective of a steady reduction in

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

the Company's flexibility to respond to changes in the business. Such changes could include lower than forecast sales, higher than expected expenses or extraordinary weather events.

The development of Muskrat Falls and the interconnection of the island electrical system to the North American grid is likely to increase Newfoundland Power's power supply costs. This, in turn, will accelerate the reduction in the proportion of operating costs to the Company's total costs on a kWh basis. This will further reduce the Company's capability to respond to unplanned or unexpected events.

First Mortgage Bond Issue Spreads

The level of uncertainty that currently exists in the Canadian economy can be observed in the relative issue spreads for Newfoundland Power's First Mortgage Bonds.[76]

Table 4-14 shows the issue spreads for the Company's First Mortgage Bonds since 2005.

Table 4-14
First Mortgage Bonds
Issue Spreads (%)
2005 to 2015

	Aug. 2005	Aug. 2007	May 2009	Nov. 2013	Sept. 2015
Issue Spread	1.06	1.40	2.75	1.70	2.15

Prior to the financial crisis of 2007/2008, the issue spreads on Newfoundland Power's First Mortgage Bonds was less than 1.5%. By 2009, the issue spread had increased to 2.75%, before

[76] The *issue spread* for the Company's First Mortgage Bonds is the amount over a 30-year Canada bond yield that is reflected in the First Mortgage Bond issue coupon rate at the time of pricing.

declining to 1.70% in 2013. In September 2015, the issue spread on the Company's Series AO First Mortgage Bonds was 2.15%.[77]

The issue spreads for Newfoundland Power indicate that the market uncertainty faced by the Company at the time of filing the 2016/2017 General Rate Application is higher than it was in November 2013, and higher than it was in the period before the 2007/2008 financial crisis.

Regulation

Newfoundland Power is regulated on a cost of service basis broadly consistent with other investor owned utilities in Canada. The regulatory framework under which the Company is regulated allows it to recover its prudently incurred costs, including its cost of capital.

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 Rate Stabilization Account ("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.[78] The RSA also recovers, or credits, as appropriate, variations in Newfoundland Power's supply costs due to

[77] Newfoundland Power typically issues First Mortgage Bonds in $75 million series. The general market requirement for inclusion in widely traded bond indices is $100 million issuances. Newfoundland Power's $75 million Series AO First Mortgage Bond issue was privately placed with four institutional investors in September 2015. The lower liquidity of smaller bond issues reduces the number of potential debt investors for the Company.

[78] 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.

changes from test year energy and demand costs.[79] The RSA effectively limits Newfoundland Power's risk of recovery of supply costs to approximately ± $640,000, which represents approximately 25% of the range of return on rate base typically approved by the Board.[80] Supply cost recovery or flow through mechanisms are common Canadian regulatory practice for distribution utilities.[81]

Newfoundland Power's Weather Normalization Reserve adjusts revenue and power supply costs to account for variations in weather.[82] 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.[83]

Newfoundland Power has variation accounts to ensure recovery of only those employee future benefit costs which are actually incurred by the Company.[84] Recovery accounts for utility

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[79] 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 $7 million since 2005.

[80] In Order No. P.U. 17 (2015), the Board approved on an interim basis a Hydro utility rate for power supply to Newfoundland Power with a demand charge of $4.32/kW. The $640,000 is calculated based upon this $4.32/kW demand charge.

[81] 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.

[82] 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).

[83] These are typically natural gas distribution utilities.

[84] 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.[85]

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.[86] Use of a range has also been justified for its incentive effect.[87]

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.[88] The typical range approved by the Board for Newfoundland Power is ± 0.18% return on rate base which broadly equates to ± 0.40% return on equity on a *pro forma* basis. The Excess Earnings Account does not provide for the recovery of shortfalls in earned returns below the range approved by the Board.[89]

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85 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 Nova Scotia, Alberta and British Columbia.

86 See The Stated Case, June 15, 1998, Newfoundland and Labrador Court of Appeal, paragraphs 25 *et. seq*.

87 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."

88 See, for example, Order Nos. P.U. 23 (2013), P.U. 32 (2010) and P.U. 46 (2009).

89 See The Stated Case, June 15, 1998, Newfoundland and Labrador Court of Appeal, paragraph 70 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).

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 some, but not all, performance based ratemaking regimes in Canada.[90] However, a cap such as that created by the Company's Excess Earnings Account is relatively rare among Canadian investor owned utilities.

4.3.3 Automatic Adjustment Formula

Background

Cost of capital formulas to determine return on equity for ratemaking purposes in Canada originated with the British Columbia Utilities Commission ("BCUC") decision to adopt a formula in 1994.[91] Following this, the National Energy Board ("NEB") and the Manitoba Public Utilities Board each adopted formulas to estimate the cost of equity for 1995.[92] The predecessor to the Alberta Utilities Commission ("AUC"), the Ontario Energy Board ("OEB") and the Régie de l'énergie ("Régie") also adopted formulas for this purpose over the period 1997 to 2004. In 1998, the Board ordered the implementation of the Formula.[93]

Following the financial crisis of 2008, a number of Canadian utility regulators, including the Board, NEB, OEB, BCUC, the Régie and AUC, reconsidered formula based approaches to

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90 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. By contrast, Alberta's current performance based regulatory scheme permits utilities to retain all earnings in excess of the allowed return; after utility returns on equity exceed the allowed return by 300 basis points (or, 3%) the existing scheme may be reexamined.

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

92 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.

93 See Order No. P.U. 16 (1998-99). 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).

annually update the cost of equity based on forecast changes in long Canada bond yields. In 2009, the NEB, BCUC and AUC chose to discontinue or suspend the operation of their formulas.[94] The only regulator that discontinued or suspended the operation of a formula and subsequently reinstated the use of a formula was the BCUC which did so in 2013. However, the reinstated BCUC formula never operated.[95]

Regulatory decisions to discontinue or suspend the use of formulas were primarily based upon the perceived inability of formulas to predict a fair forecast cost of equity when long Canada bond yields were unusually low. The Board reached a similar conclusion in 2013. In assessing the continued use of the Formula for Newfoundland Power, the Board concluded that:

> "…..the evidence is clear that the formula as it is currently structured may not result in a fair return for Newfoundland Power in the current circumstances. Long-term Canada bond yields are abnormally low which is particularly problematic in the operation of the automatic adjustment formula. In the absence of a clear relationship between the long-term Canada bond yield and the cost of equity it is difficult to see that the established return can be appropriately adjusted for 2015 without the exercise of further judgement…..
>
> The Board notes that the experts forecast a period of relative stability in the bond markets with continued low long-term Canada bond yields and a gradual return to normal levels over the next several years."[96]

In discontinuing use of the Formula in 2013, the Board indicated that "…..in the absence of a further Order of the Board, [the Formula] will be used to establish a fair return for

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[94] In 2009, both the NEB and BCUC eliminated their formulas. 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).

[95] The formula adopted by the BCUC in 2013 only operates when the long Canada bond yield reaches 3.8%. See BCUC Decision L-53-13, September 16, 2013. The long Canada bond yield has not reached 3.8% since 2013.

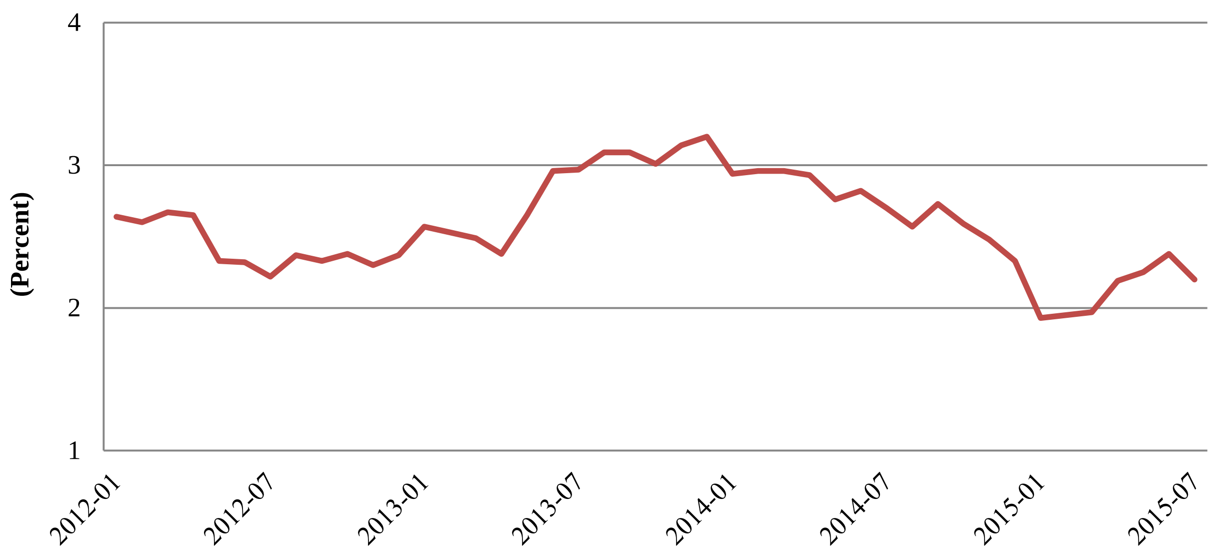
[96] Order No. P.U. 13 (2013), page 36, lines 38-44 and page 37, lines 10-12.

Newfoundland Power following its next general rate application."[97]

Bond Yields Since 2012

Chart 4-1 shows actual 30-year Canada bond yields from January 2012 to July 2015.

Chart 4-1
30-Year Canada Bond Yields
Actual
2012 - 2015



In the 3½ years from January 2012 to July 2015, 30-year Canada bond yields have been stable, largely remaining in the range of 2% - 3%.

In September 2012, when Newfoundland Power filed its last general rate application, 30-year Canada bond yields averaged 2.33%. In September 2015, 30-year Canada bond yields averaged 2.24%.

[97] Order No. P.U. 13 (2013), page 37, lines 21-23.

It seems clear that the expected gradual return to normal levels of long Canada bond yields has not yet occurred. When such a return might occur is dependent upon a number of factors, including government intervention to reduce borrowing rates to address financial risks to the broader Canadian economy. Such intervention may continue for some time yet. In its *July 2015 Monetary Policy Report Summary*, the Bank of Canada noted that:

> "…..Canada's economy is undergoing a significant and complex adjustment. *Additional monetary stimulus is required at this time to help return the economy to full capacity and inflation sustainably to target.* Taking all this into consideration, on 15 July, the Bank lowered the overnight rate target to ½ per cent."[98] (emphasis added)

Conclusion

Section 80 of the *Public Utilities Act* entitles Newfoundland Power to an opportunity to earn a just and reasonable return *each* year. In Order No. P.U. 13 (2013), the Board suspended use of the Formula due to abnormally low long Canada bond yields and the problematic impact that they had in the operation of the Formula.

Since Order No. P.U. 13 (2013), there has not been an appreciable change in long Canada bond yields. Further, bank forecasts do not appear to indicate that a return to more normal long Canada bond yields is imminent. In fact, recent indication from the Bank of Canada is that additional monetary stimulus in the form of lower interest rates remains a policy option for the Bank of Canada in dealing with the nation's current economic circumstances.

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[98] *July 2015 Monetary Policy Report Summary*, Bank of Canada, page 2.

The current circumstances do not justify the Board ordering the use of the Formula to establish a fair return for Newfoundland Power beyond 2017.

4.3.4 Impact of Proposed Returns

Exhibit 5, shown in *Volume 2, Exhibits & Supporting Materials*, compares Newfoundland Power's forecast financial performance for 2016 and 2017 based on existing customer rates and proposed customer rates which incorporate the proposals contained in this Application.

Table 4-15 provides a summary comparison of Newfoundland Power's regulated returns under existing customer rates and proposed rates.

Table 4-15
Comparative Rates of Return
2016 & 2017

	2016E	**2016P**	**2017E**	**2017P**
Return on Rate Base (%)	6.96	7.66	6.61	7.64
Return on Equity (%)	7.96	9.50	7.22	9.50

Newfoundland Power's First Mortgage Bonds are a primary source of long-term debt financing for the assets required to provide service to the Company's customers.[99] Because the First Mortgage Bonds are a secured first charge against Newfoundland Power's utility assets, they are attractive to investors and provide relatively low-cost financing. The Company's First Mortgage

[99] At December 31, 2014, Newfoundland Power had a total of approximately $484 million in First Mortgage Bonds outstanding.

Bonds are rated A by DBRS and A2 by Moody's.[100] The trust deed which secures the First Mortgage Bonds requires, in effect, an interest coverage of 2.0 times or higher for the Company to issue additional bonds.[101] Under existing customer rates, by 2017, Newfoundland Power will have only limited ability to issue First Mortgage Bonds.

In this Application, Mr. James Coyne of Concentric Energy Advisors has provided expert opinion on a fair return on equity and appropriate capital structure for Newfoundland Power for 2016 and 2017. In Mr. Coyne's opinion, a fair return on equity for Newfoundland Power for 2016 and 2017 is 9.5%, based upon a capital structure with a target equity ratio of 45%. This expert opinion is reflected in the customer rates proposed in this Application.

Table 4-16 shows Newfoundland Power's credit metrics under existing customer rates and under the customer rates proposed in this Application.

Table 4-16
Credit Metrics
Existing and Proposed
2016 & 2017

	2016E	**2016P**	**2017E**	**2017P**
Pre-tax Interest Coverage (times)	2.2	2.5	2.1	2.5
Cash Flow Interest Coverage (times)	3.9	4.1	3.8	4.2
Cash Flow Debt Coverage (%)	17.5	18.8	16.9	19.3

[100] Moody's Investors Service A2 rating on the Company's First Mortgage Bonds is based upon the first mortgage security offered by the bonds. This represents a 2 notch upgrade from a senior unsecured investment grade regulated utility debt security of Baa1. The higher A2 rating permits Newfoundland Power to access financing at lower rates. See *Exhibit 4* in *Volume 2, Exhibits & Supporting Materials*, page 3.

[101] Article 6.2 of the trust deed securing Newfoundland Power's First Mortgage Bonds provides "***6.2 Earnings Test***. No Additional Bonds shall be certified and delivered hereunder unless the Net Earnings of the Company for the Earnings Period selected by the Directors shall have been at least two (2) times the maximum annual interest charges on all Bonds to be outstanding after the proposed issue of Additional Bonds."

Under the customer rates proposed in this Application, Newfoundland Power's forecast credit metrics and, in particular, its forecast interest coverage, 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 (i) the continued financial integrity of the Company and (ii) Newfoundland Power's ability to attract capital on reasonable terms.

4.4 REGULATORY AMORTIZATIONS

4.4.1 Overview

Table 4-17 summarizes the amortization of regulatory deferrals approved by the Board in Order No. P.U. 13 (2013) and the amortization of regulatory deferrals proposed in this Application.

Table 4-17
Amortization of Regulatory Deferrals
***Pro forma* Revenue Requirement Impact**
2013 to 2017F
($000s)

	2013	**2014**	**2015F**	**2016F**	**2017F**
2011 & 2012 Cost Recovery Deferrals[102]	1,575	1,575	1,575	-	-
2012 Cost of Capital Recovery Deferral[102]	829	829	829	-	-
2013/2014 Hearing Costs Deferral[102]	321	322	322	-	-
Weather Normalization Reserve[102]	(2,335)	(2,335)	(2,335)	-	-
2013 Revenue Shortfall[102]	(3,172)	1,586	1,586	-	-
2016/2017 Hearing Costs Deferral[103]	-	-	-	400	400
2016 Revenue Shortfall[104]	-	-	-	(3,276)	1,638
Revenue Requirement Impact	**(2,782)**	**1,977**	**1,977**	**(2,876)**	**2,038**

[102] These amortizations were agreed in Newfoundland Power's 2013/2014 General Rate Application and approved by the Board in Order No. P.U. 13 (2013).

[103] This amortization is proposed in this Application and is $1,200,000/3 = $400,000. See *Section 4.4.2: 2016/2017 Hearing Costs*.

[104] This amortization is proposed in this Application. For 2016, it represents deferral of 24/30 x $4,095,000, or $3,276,000. For 2017, it represents recovery of 12/30 x $4,095,000, or $1,638,000. See *Section 4.4.3: 2016 Revenue Shortfall*.

4.4.2 2016/2017 Hearing Costs

Newfoundland Power estimates approximately $1.2 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 commencing in 2016.

This proposed treatment of 2016/2017 General Rate Application hearing costs is consistent with past practice of the Board.[105]

4.4.3 2016 Revenue Shortfall

Based upon a July 1, 2016 implementation, customer rates designed to recover the 2017 revenue requirement would result in a $4,095,000 shortfall in recovering the 2016 revenue requirement. The Company is proposing a revenue amortization over 30 months commencing July 1, 2016 and ending December 31, 2018 to recover this shortfall.

The proposed treatment of the 2016 revenue requirement shortfall is consistent with past practice of the Board.[106]

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[105] 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), P.U. 43 (2009) and P.U. 13 (2013)).

[106] See Order No. P.U. 13 (2013).

SECTION 5: RATE BASE & REVENUE REQUIREMENTS

5.1 OVERVIEW

This section of the evidence addresses the Company's forecast 2016 and 2017 average rate base and forecast 2016 and 2017 revenue requirements.

Based on the Company's proposals in this Application, forecast 2016 and 2017 average rate base are approximately $1,060 million and $1,105 million, respectively.

Based on the Company's proposals in this Application, forecast 2016 and 2017 revenue requirements are approximately $670 million and $683 million, respectively.

To generate the increase in revenue necessary to meet the Company's forecast revenue requirements in 2016 and 2017, an average increase in existing customer rates of approximately 3.1% effective July 1, 2016 will be required.

5.2 2016 AND 2017 RATE BASE

Exhibit 6, in *Volume 2, Exhibits & Supporting Materials*, shows Newfoundland Power's forecast 2016 and 2017 average rate base.

Newfoundland Power's forecast 2016 and 2017 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 *2016 and 2017 Rate Base Allowances* is found in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 3.*

The Company's forecast 2016 and 2017 average rate bases are approximately $1,060 million and $1,105 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 2016 and 2017 average rate base includes the Company's forecast capital expenditures and is calculated in accordance with established practice and Board orders.[4]

5.3 2016 AND 2017 REVENUE REQUIREMENTS

5.3.1 Summary of Revenue Requirements

Exhibit 7, in *Volume 2, Exhibits & Supporting Materials*, shows Newfoundland Power's 2016 and 2017 forecast revenue requirements.[5]

The Company revenue requirements used to establish electricity rates are forecast to be approximately $670 million in 2016 and approximately $683 million in 2017.

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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 *2016 Capital Budget Application* filed on June 23, 2015.

[3] Annual depreciation expense is currently calculated using the composite depreciation rates approved by the Board in Order No. P.U. 13 (2013). The Company is proposing composite depreciation rates based on the *2014 Depreciation Study*, found in *Volume 3, Expert Evidence & Studies, Tab 2*. See *Section 4.2.3: Depreciation*.

[4] The forecast capital expenditures for 2016 and 2017 are described in detail in the *2016 Capital Budget Application*. The Board approved this application in Order No. P.U. 28 (2015).

[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.

Table 5-1 shows a summary of Newfoundland Power's 2016 and 2017 forecast revenue requirements and the revenue required to be recovered from customer rates.

Table 5-1
Summary of Revenue Requirements
2016F & 2017F
($000s)

	2016F	**2017F**
Power Supply Cost	448,197	447,927
Operating Costs[6]	58,523	60,170
Employee Future Benefit Costs	22,176	17,892
Regulatory Amortizations and Deferrals	(3,276)	1,638
Depreciation	55,535	58,573
Income Taxes[6]	18,585	19,598
Return on Rate Base	81,214	84,416
Revenue Requirements	**680,954**	**690,214**
Adjustments		
Interest on Security Deposits	24	24
2013 Excess Earnings	(68)	-
Other Revenue	(4,805)	(4,832)
Energy Supply Cost Variance Adjustments	(4,526)	-
CDM Program Amortization	(1,894)	(2,828)
Revenue Requirements from Rates	**669,685**	**682,578**

[6] For revenue requirement purposes, operating costs and income taxes do not include non-regulated expenses.

5.3.2 Costs and Depreciation

Table 5-2 shows forecast 2016 and 2017 power supply costs.

Table 5-2
Power Supply Costs
2016F & 2017F
($000s)

	2016F	**2017F**
Existing	449,006	450,829
Elasticity Impact	(809)	(2,902)
Proposed	**448,197**	**447,927**

Table 5-3 shows forecast 2016 and 2017 operating costs.[7]

Table 5-3
Operating Costs
2016F & 2017F
($000s)

	2016F	**2017F**
Existing	58,123[8]	59,770[9]
2016 Hearing Costs[10]	400	400
Proposed	**58,523**	**60,170**

7 *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: Customers* and *Section 3.5*: *2016 and 2017 Operating and Capital Costs.*

8 Existing operating costs in 2016 include (i) gross operating cost of approximately $59.8 million (see *Exhibits 1 and 2*); (ii) plus amortization of CDM costs of approximately $1.9 million as approved by the Board in Order No. P.U.13 (2013);(iii) less general expenses capitalized of approximately $3.5 million.

9 Existing operating costs in 2017 include (i) gross operating cost of approximately $60.1 million (see *Exhibits 1 and 2*); (ii) plus amortization of CDM costs of approximately $2.8 million as approved by the Board in Order No. P.U. 13 (2013);(iii) less general expenses capitalized of approximately $3.2 million.

10 See *Section 4.4.2: 2016/2017 Hearing Costs*.

1 Table 5-4 shows forecast 2016 and 2017 employee future benefits costs.

2

Table 5-4
Employee Future Benefits Costs
2016F & 2017F
($000s)

	2016F	**2017F**
Pension Plans[11]	13,404	9,600
OPEBs[12]	8,772	8,292
Proposed	**22,176**	**17,892**

3

4 Table 5-5 shows forecast amortization of 2016 and 2017 deferred cost recoveries.

5

Table 5-5
Amortization of Deferred Cost Recoveries
2016F & 2017F
($000s)

	2016F	**2017F**
2016 Revenue Shortfall Amortization[13]	(3,276)	1,638
Proposed	**(3,276)**	**1,638**

[11] See *Section 4.2.4: Employee Future Benefits, Pensions*.
[12] See *Section 4.2.4: Employee Future Benefits, OPEBs*.
[13] The Company is proposing deferral of an approximately $4.1 million revenue shortfall in 2016. The revenue shortfall is due to timing differences resulting from the July 1, 2016 customer rate implementation date. See *Section 4.4: Regulatory Amortizations*, page 4-43.

Table 5-6 shows forecast 2016 and 2017 depreciation costs.

Table 5-6
Depreciation Costs
2016F & 2017F
($000s)

	2016F	**2017F**
Depreciation[14]	55,535	58,573
Proposed Depreciation	**55,535**	**58,573**

Table 5-7 shows forecast 2016 and 2017 income taxes.

Table 5-7
Income Taxes
2016F & 2017F
($000s)

	2016F	**2017F**
Existing[15]	15,486	14,889
Tax Effects of Application Proposals[16]	3,099	4,709
Proposed[17]	**18,585**	**19,598**

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14 The Company is proposing to implement the depreciation rates from the *2014 Depreciation Study* effective January 1, 2016 and to amortize the accumulated reserve variance of $12.2 million over the composite remaining life of the assets. See *Section 4.2.3: Depreciation*.

15 See *Exhibit 5* in *Volume 2, Exhibits & Supporting Materials*, line 22.

16 The tax effects of the Application proposals are as follows:

	($000s)	
	2016	**2017**
Increase in Forecast Revenue from Rates, *Exhibit 7*, line 22	7,910	17,332
Change in Transfers to the RSA and Excess Earnings, *Exhibit 7*, lines 17-19	7	(1,057)
Increase in Taxable Revenue	7,917	16,275
Reduction in Tax Deductible Expenses (purchased power, operating, interest)	(429)	2,856
Increase in Taxable Income	7,488	19,131
Tax Rate	29.0%	29.0%
Change in Cash Income Taxes	2,172	5,548
Change in Future Income Taxes	927	(839)
Change in Total Income Taxes	**3,099**	**4,709**

17 See *Exhibit 5* in *Volume 2, Exhibits & Supporting Materials*, line 22.

5.3.3 Return on Rate Base

Exhibit 8, in *Volume 2, Exhibits & Supporting Materials*, shows Newfoundland Power's proposed 2016 and 2017 return on rate base.

Table 5-8 summarizes the proposed 2016 and 2017 return on rate base and rate of return on rate base.

Table 5-8
Return on Rate Base
2016F & 2017F
($000s)

	2016F	**2017F**
Forecast Average Rate Base	1,060,331[18]	1,105,064[19]
Forecast Regulated Returns		
Debt	35,405	36,749
Preferred Equity	552	552
Common Equity	45,257	47,115
Return on Rate Base	**81,214**	**84,416**
Rate of Return on Rate Base (%)	**7.66**[20]	**7.64**[21]

18 2016F average rate base is shown in *Exhibit 6* in *Volume 2, Exhibits & Supporting Materials*.
19 2017F average rate base is shown in *Exhibit 6* in *Volume 2, Exhibits & Supporting Materials*.
20 The forecast rate of return on rate base for 2016 is calculated as ($81,214,000/$1,060,331,000= 7.66%), as shown in *Exhibit 8* in *Volume 2, Exhibits & Supporting Materials.*
21 The forecast rate of return on rate base for 2017 is calculated as ($84,416,000/$1,105,064,000= 7.64%), as shown in *Exhibit 8* in *Volume 2, Exhibits & Supporting Materials.*

1 **5.3.4 Deductions from Revenue Requirements**

2 Table 5-9 shows the forecast 2016 and 2017 deductions from revenue requirements.

3

Table 5-9
Deductions from Revenue Requirements
2016F & 2017F
($000s)

	2016F	2017F
Other Revenue	(4,805)[22]	(4,832)[23]
Transfers to the RSA	(6,420)[24]	(2,828)[25]
2013 Excess Earnings	(68)[26]	-
Interest on Security Deposits[27]	24	24
Proposed	**(11,269)**	**(7,636)**

22 See *Exhibit 5* in *Volume 2, Exhibits & Supporting Materials*, page 1 of 9, line 11.
23 See *Exhibit 5* in *Volume 2, Exhibits & Supporting Materials*, page 1 of 9, line 11.
24 The 2016 transfers to the RSA include a $4,526,000 balance in the Energy Supply Cost Variance Reserve at March 1, 2017 and $1,894,000 related to the amortization of CDM program costs.
25 The 2017 transfer to the RSA is due to $2,828,000 related to the proposed amortization of conservation program costs.
26 2013 Excess Earnings as shown in Return 13 of Newfoundland Power's 2013 Annual Report to the Board.
27 Interest on customer security deposits is not included in the determination of revenue requirements.

5.3.5 Required Revenue Increase

Table 5-10 shows a forecast increase in revenue from rates of approximately $8.8 million in 2016 required to meet the Company's proposed 2016 revenue requirements and approximately $20.1 million required to meet the Company's proposed 2017 revenue requirements.

Table 5-10
Required Revenue Increases
2016F & 2017F
($000s)

	2016F	**2017F**
Proposed Revenue From Rates	**669,685**	**682,578**
Revenue From Existing Rates	(661,775)	(665,246)
Elasticity Impacts[28]	805	2,803
Required Increase in Revenue from Rates	**8,715**	**20,135**

[28] See *Exhibit 9* in *Volume 2, Exhibits & Supporting Materials*.

SECTION 6: CUSTOMER RATES

6.1 OVERVIEW

The number of customers served by Newfoundland Power is forecast to increase by 0.8% in 2016 and 0.7% in 2017. Energy sales are forecast to grow by 0.4% in 2016 and 0.1% in 2017. Demand is forecast to increase by 0.1% in 2016 and 0.4% in 2017.

In this Application, the Company seeks an average increase in customer rates of 3.1%. Newfoundland Power's rate change plan targets revenue to cost ratios in a range of 90% to 110%. To achieve these target ratios, proposed average increases of 3.6% for domestic customers and 0.6% for customers served under Rate 2.3 are required.

This section of the Company evidence describes proposals to introduce new customer charges for Rate 2.1 and modifications to the Curtailable Service Option available to Rate 2.3 and 2.4 customers.

A review of Newfoundland Power's existing supply cost mechanisms indicates that those mechanisms continue to be consistent with sound public utility practice and Canadian regulatory practice.

6.2 CUSTOMER, ENERGY AND DEMAND FORECAST

6.2.1 The Customers Served

Newfoundland Power is the largest distributor of electricity on the Island Interconnected system and is responsible for retail pricing for the approximately 283,000 customers served by the system.[1]

Table 6-1 shows the forecast percentage of total customers and sales for each rate class for the 2017 test year.

Table 6-1
Newfoundland Power Customer Base
2017F

Rate	Class of Service	% of Total Customers	% of Total Energy Sales
1.1	Domestic	87.0	61.6
2.1	General Service 0-100 kW (110 kVA)	8.4	13.4
2.3	General Service 110-1000 kVA	0.5	17.0
2.4	General Service 1000 kVA and Over	-[2]	7.5
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 62% of Newfoundland Power's annual energy sales are to Domestic customers.

[1] Hydro serves approximately 23,800 customers on the Island Interconnected system. 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 system.

[2] The 63 customers in Rate 2.4 comprise less than 0.01% of total customers.

6.2.2 Forecast

Newfoundland Power's *Customer, Energy and Demand Forecast* is found in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 4*.

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 6-2 shows the Company's forecast number of customers for 2015, 2016 and 2017.

Table 6-2
Forecast Number of Customers
2015F to 2017F

	2015F	**2016F**	**2017F**
Domestic	226,839	228,654	230,327
General Service			
0-100 kW (110 kVA)	22,157	22,255	22,345
110-1000 kVA	1,216	1,223	1,233
1000 kVA and Over	63	63	63
Total General Service	23,436	23,541	23,641
Street and Area Lighting	10,818	10,894	10,963
Total Customers	**261,093**	**263,089**	**264,931**

The number of customers is forecast to increase by 0.8% in 2016 and 0.7% in 2017.

[3] See Appendices B and C to the *Customer, Energy and Demand Forecast*, found in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 4.*

Table 6-3 shows the Company's forecast energy sales for 2015, 2016 and 2017.

Table 6-3
Energy Sales Forecast
2015F to 2017F
(GWh)

	2015F	**2016F**	**2017F**
Domestic	3,655.7	3,678.4	3,690.7
General Service			
0-100 kW (110 kVA)	791.3	800.7	804.5
110-1000 kVA	1,002.9	1,004.9	1,015.7
1000 kVA and Over	481.1	468.4	446.8
Total General Service	2,275.3	2,274.0	2,267.0
Street and Area Lighting	32.1	32.2	32.4
Total Energy Sales	**5,963.1**	**5,984.6**	**5,990.1**

Energy sales are forecast to increase by 0.4% in 2016 and 0.1 % in 2017.[4]

Table 6-4 shows the Company's forecast demand for 2015, 2016 and 2017.

Table 6-4
Demand Forecast
2015F to 2017F
(MW)

	2015F	**2016F**	**2017F**
Native Peak[5]	1,404.9	1,406.1	1,411.3
Purchased[6]	1,276.0	1,277.2	1,282.4

[4] The sales forecast includes elasticity effects of 8.0 GWh in 2016 and 27.9 GWh in 2017 as a result of the proposed July 1, 2016 average rate increase of 3.1%.

[5] Native peak is the maximum demand served by Newfoundland Power. The 2015 native peak reflects the forecast for the winter period of December 2015 to March 2016.

[6] Purchased demand is the native peak less load curtailment by Newfoundland Power customers and Company owned facilities and the 117.9 MW generation credit provided for in Hydro's wholesale rate structure.

Demand is forecast to increase by approximately 0.1% in 2016 and 0.4% in 2017. Demand purchases from Hydro are forecast to increase by 0.1% in 2016 and 0.4% in 2017.

6.3 RATE CHANGE PLAN

6.3.1 Embedded Cost of Service Study

Newfoundland Power assesses the fairness of its customer 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 (the "revenue to cost ratio").

The Company has prepared an embedded cost of service study to reflect 2014 costs adjusted to reflect the *pro forma* impact of Hydro's Interim Rate change on July 1, 2015 (the "Cost of Service Study"). The Cost of Service Study is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 5*.

Table 6-5 shows the current revenue to cost ratio for each rate class as indicated by the Cost of Service Study.

Table 6-5
Cost of Service Study
Revenue to Cost Ratios

Class of Service	Rate Code	Revenue to Cost Ratios (%)
Domestic	1.1	95.6
General Service 0-100 kW (110 kVA)	2.1	108.6
General Service 110-1000 kVA	2.3	111.9
General Service 1000 kVA and Over	2.4	104.5
Street and Area Lighting	4.1	103.4

Maintaining revenue to cost ratios for each class within a range of 90% to 110% has been an accepted approach to achieving fairness in rate design by avoiding undue cross-subsidization among the various classes.[7] The revenue to cost ratio for the General Service Rate 2.3 (110-1000 kVA class) is greater than 110%.[8] The Company's rate proposals in this Application include bringing the revenue to cost ratios for that class within the target range of 90% to 110%.[9]

To maintain revenue to cost ratios within the 90% to 110% range, Newfoundland Power proposes to implement (i) a lower than average rate increase for customers served under General Service Rate 2.3 and (ii) a higher than average rate increase for customers served under Domestic Rate 1.1.[10]

7 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%, …".

8 The primary cause of General Service Rate 2.3 having a revenue to cost ratio higher than 110% relates to the higher increase in demand costs relative to energy costs since Newfoundland Power's *2013/2014 General Rate Application*. Amongst the causes for this is the lower cost of fuel burned at Hydro's Holyrood thermal generating station.

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's *2010 General Rate Application*, Evidence, page 5-9, line 13, *et. seq.*.

10 Since the Domestic class accounts for approximately 62% 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.

Table 6-6 shows the proposed July 1, 2016 relative rate changes by customer class and the resulting *pro forma* revenue to cost ratios resulting from those changes.

Table 6-6
Proposed Relative Rate Changes by Class

Rate	Class	Relative to Average	*Pro forma* Revenue to Cost Ratio %
1.1	**Domestic**	**0.5% above**[11]	**96.1**
2.1	General Service 0-100 kW (110 kVA)	Equal	108.6
2.3	**General Service 110-1000 kVA**	**2.5% below**	**109.4**
2.4	General Service 1000 kVA and Over	Equal	104.5
4.1	Street and Area Lighting	Equal	103.3

The proposed relative changes in rates will result in the *pro forma* revenue to cost ratios for all Newfoundland Power customer classes being within the target range of 90% to 110%.

6.3.2 Marginal Cost Outlook

Historically, Newfoundland Power has designed rates with consideration of marginal energy and capacity costs to ensure rates reasonably reflect marginal cost.[12] This is consistent with sound rate making principles.[13]

[11] The Domestic class increase relative to average will vary by 0.5% 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] A primary justification of the Retail Rate Review agreed in settlement of Newfoundland Power's *2008 General Rate Application* was the consideration of new rate designs to encourage increased energy conservation and efficiency. See Order No. P.U. 32 (2007) page 51-52.

[13] See, for example, Bonbright, Danielsen and Kamerschen, *Principles of Public Utility Rates (2d ed.)*, Public Utilities Reports (1988), page 382, *et.seq.*

The Muskrat Falls development will be the primary source of any additional power supply requirements for Newfoundland Power. The cost of Muskrat Falls production and associated transmission systems is currently uncertain. This adds significant uncertainty to Newfoundland Power's marginal cost outlook.

Hydro is currently evaluating the system marginal costs following completion of Muskrat Falls and the interconnection to the North American grid. Current short-term marginal supply costs tend to reflect the price of fuel at Hydro's Holyrood thermal generating station. Following interconnection to the North American grid, this will no longer be the case. The latest marginal cost estimates for energy and capacity for the Island Interconnected system indicate that marginal costs following interconnection will be materially different than current short-term marginal costs.[14]

The current uncertainty associated with marginal capacity and energy costs for the Island Interconnected system suggests that no material increases or decreases to specific rate components to reflect marginal costs would be appropriate at this time.

[14] The latest estimates of marginal costs for the Island Interconnected system provided by Hydro for the purposes of customer energy conservation planning generally indicate declining energy costs and increasing capacity costs over the 2015-2035 time horizon. However , Hydro is currently reassessing marginal costs; so these estimates may not be reliable.

6.4 PROPOSED RATES

6.4.1 General

Schedule 1 to the Application sets out Newfoundland Power's proposed customer rates to be effective July 1, 2016.

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 9, in *Volume 2, Exhibits & Supporting Materials,* provides a reconciliation of Newfoundland Power's forecast revenue from rates to the Company's revenue requirements for 2016 and 2017.

Exhibit 10, in *Volume 2, Exhibits & Supporting Materials,* provides the computation of the average increase in customer rates of 3.1% proposed by the Company.

Exhibit 11, in *Volume 2, Exhibits & Supporting Materials*, provides a comparison of Newfoundland Power's existing and proposed customer rates.[15]

6.4.2 Rate Structure Changes

Rate 2.1

The Company is proposing to implement separate basic customer charges in General Service Rate 2.1 for customers that have (i) unmetered service, (ii) single phase service and (iii) three

[15] The existing and proposed rates reflect the RSA and MTA factors effective July 1, 2015.

phase service.[16] This change is proposed to reflect the different costs to provide each type of service.[17]

Table 6-7 shows the number of General Service customers served under Rate 2.1 that have unmetered, single phase or three phase service and the average customer cost associated with that service.[18]

Table 6-7
General Service Rate 2.1
Customers and Customer Cost

Service	No. of Customers	Monthly Cost per Cutstomer ($)
Unmetered	1,841	22.4
Single Phase	15,076	30.3
Three Phase	5,096	42.5

The existing Basic Customer Charge for Rate 2.1 is $21.93/month. The Minimum Three Phase Charge is $36.03/month.

The Company proposes to initially set the Rate 2.1 Basic Customer Charge (i) for unmetered service at $4.00 less than the single phase service charge and (ii) for three phase service at $6.00

16 Unmetered customers typically have loads that are predictable and can be estimated, thereby eliminating the requirement for metering. The most common types of unmetered services are traffic lights and communications equipment owned by telecommunications companies. Single phase service is used by smaller General Service customers such as corner stores. Three phase service tends to be used by somewhat larger General Service customers such as strip malls or facilities with motorized equipment such as compressors.

17 This matter was addressed in Newfoundland Power's January 2009 *Rate Design Report* which was part of the Company's Retail Rate Review. The justification for the different customer charges for unmetered, single phase and three phase service is provided in the *Rate Design Report.* The *Rate Design Report* also indicated that Unwarranted Three Phase Charges would be unnecessary following the introduction of separate customer charges. See *Rate Design Report*, *Section 4.1.2: Basic Customer Charges*, pages 60 to 62.

18 The number of customers are year end actuals for 2014. The Embedded Costs were determined from the 2014 Cost of Service Study.

greater than the single phase service charge. The proposed initial change in the basic customer charges is less than the total indicated cost differential to limit customer impacts resulting from the changes. The Company also proposes to set the Minimum Monthly Three Phase Charge to be $12.00 above the single phase service basic customer charge to reflect the full cost differential between three phase and single phase service.[19]

Overall, the Basic Customer Charge changes in General Service Rate 2.1 will be set to provide an average revenue increase from Basic Customer Charges equal to the proposed overall average class increase.

The proposed changes in the Basic Customer Charge for General Service Rate 2.1 will eliminate the necessity for Newfoundland Power to require customers to pay an Unwarranted Three Phase Charge. The elimination of the Unwarranted Three Phase Charge will require changes to existing regulations and policies governing the Company's provision of service to its customers.

A report on the *Elimination of Unwarranted Three Phase Charge* describing the required changes to regulations and policies is provided in *Volume 2, Exhibits and Supporting Materials, Reports, Tab 7*.

[19] The proposed Miniumum Three Phase Charge is $33.65. This is $2.38 lower than the exisiting Minimum Three Phase Charge of $36.03.

6.4.3 Changes to Rate Components

Domestic

The Company is proposing an increase to the Domestic class of 3.6%. The increase is higher than the overall average increase being proposed by the Company of 3.1% to accommodate the lower than average increase required for customers served under General Service Rate 2.3.[20]

It is proposed that the Basic Customer Charges, the Energy Charges, Demand Charges, and the Minimum Monthly Charge for Domestic Rate 1.1 be increased by the average Domestic Class increase to the extent possible.[21]

Rate 2.1 General Service (0-100kW (110 KVA)) Class

The Company is proposing an overall increase to customers served under General Service Rate 2.1 equal to the the overall average increase being proposed by the Company of 3.1%.

It is proposed that the Basic Customer Charges, Energy Charge, Demand Charges, and the Maximum and Minimum Monthly Charge be subject to the overall Rate 2.1 Class increase to the extent possible.[22]

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[20] For greater detail see *Section 6.3.1: Embedded Cost of Service Study*, pg. 6-5, line 4 *et. seq*.

[21] The maintenance of a 5.00 $/month differential between service up to 200 Amps and service over 200 Amps will result in some components of Rate 1.1 increasing by an amount different than the proposed average class increase of 3.6%.

[22] The introduction of new Basic Customer Charges in Rate 2.1 and the maintenance of a 2.50 $/kW differential between winter and non-winter Demand Charges in Rate 2.1 will result in some components of Rate 2.1 increasing by an amount different than the proposed *average* class increase.

Rate 2.3 General Service (110 – 1000 kVA)

The Company is proposing an overall increase to the General Service customers supplied under Rate 2.3 of 0.6%. The overall increase is lower than the average increase being proposed by the Company of 3.1% to ensure all class revenue to cost ratios are maintained within reasonable limits.[23]

It is proposed that the Basic Customer Charge, Energy Charges and Demand Charges be subject to the overall Rate 2.3 Class increase to the extent possible.[24]

Rate 2.4 General Service (> 1000 kVA)

The Company is proposing an overall increase to the General Service customers served under Rate 2.4 equal to the the overall average increase of 3.1%.

It is proposed that the Basic Customer Charge, Energy Charges, Demand Charges and Maximum Monthly Charge be subject to the overall Rate 2.4 Class increase to the extent possible.[25]

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[23] See *Section 6.3.1: Embedded Cost of Service Study*, page 6-5, line 4 *et. seq*.

[24] The maintenance of a 2.50 $/kW differential between winter and non-winter Demand Charges in Rate 2.3 and increasing the energy charge in the Maximum Monthly Charge by the proposed average *overall* increase of 3.1% will result in some components of Rate 2.3 increasing by an amount different than the proposed average *class* increase of 0.6%. Increasing the energy charge by the proposed average *overall* increase ensures inter-class parity for all General Service customers by ensuring the energy charge in the Maximum Monthly Charge is the same.

[25] The maintenance of a 2.50 $/kW differential between winter and non-winter Demand Charges in Rate 2.4 will result in some components of Rate 2.4 increasing by an amount different than the proposed average increase of 3.1%.

Rate 4.1 Street and Area Lighting Service

The Company is proposing an overall increase to the Street and Area Lighting Service Rate equal to the overall average increase of 3.1%.[26]

6.5 CURTAILABLE SERVICE OPTION

Newfoundland Power provides a Curtailable Service Option for customers served under General Service Rates 2.3 and 2.4. In 2014, Newfoundland Power reviewed its Curtailable Service Option with a view to maintaining and, if possible, increasing the amount of contracted curtailable load on the Island Interconnected system.

A report on the *Curtailable Service Option Review* is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 8*.

As a result of this review, Newfoundland Power is proposing to modify the Curtailable Service Option. Firstly, the Company proposes to modify the penalty clause to (i) increase the number of failures allowed to 4 from 3; (ii) reduce the 50% credit reduction for the first failure to a 25% credit reduction; and (iii) introduce a tiered system which permits a customer to secure 50% of the curtailment credit achieved following the 5th curtailment request in a winter season. Secondly, the Company proposes to modify the availability of the Curtailable Service Option to permit customers with multiple facilities to aggregate those facilities for the purposes of meeting the minimum 300 kW demand reduction required to take advantage of the rate option.

[26] The Street and Area Lighting rates will continue to be developed based on recovering embedded costs with the price of fixtures, poles and wiring varying in a manner reflective of differences in their fixed costs and variable operating costs. The Street and Area Lighting rate and the Rate Stabilization Clause will no longer refer to mercury vapour lights as none remain in service.

6.6 SUPPLY COST MECHANISMS

Newfoundland Power has examined its regulatory supply costs mechanisms to ensure their continued effectiveness and efficiency in permitting the recovery of purchased power costs.

A report on the Company's review of supply cost mechanisms is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab 9.*

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; and

2. current mechanisms provide reasonable incentives for the Company to further customer conservation of demand and energy.