DELIVERED BY HAND

May 27, 2021

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

Dear Ms. Blundon:

Re: 2022/2023 General Rate Application

1. Background

In Order No. P.U. 2 (2019), the Board ordered, amongst other things, that Newfoundland Power Inc. ("Newfoundland Power" or the "Company") file its next general rate application no later than June 1, 2021.

In February 2021, the Board requested that Newfoundland Power include with its next general rate application a review of its methodology and cost ratios used to determine General Expenses Capitalized ("GEC"). The Board requested that the review address why pension costs are included in GEC and how including pension costs in a labour loader would impact revenue requirement and customer rates. Newfoundland Power's review of its GEC is provided in *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized*.

2. The Filing

Enclosed with this letter are the original and 9 copies of a general rate application for a review of Newfoundland Power's 2022 and 2023 costs and customer rates (the "Application").

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5364 • FAX (709) 737-2974 • **khopkins@newfoundlandpower.com**

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

Volume 1: ***Application, Company Evidence and Exhibits:*** *this Volume contains this letter, the formal application, company evidence and supporting exhibits.*

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

Volume 3: ***Expert Evidence:*** *this Volume contains the Depreciation Study of Mr. John Wiedmayer, Gannett Fleming Valuation and Rate Consultants LLC and the cost of capital evidence of Mr. James Coyne of Concentric Energy Advisors Inc.*

3. Application Proposals

Customer Rates

The Application proposes that the Board approve an overall average increase in Newfoundland Power's current customer rates of 0.8%, with effect from March 1, 2022.

The increase in proposed customer rates by class are as follows:

Rate Class	***Average Increase***
Domestic	0.8%
General Service 0-100 kW (110 kVA)	0.8%
General Service 110-1000 kVA	0.8%
General Service 1000 kVA and Over	0.8%
Street and Area Lighting	0.8%

Cost of Capital

The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2022 and 2023 is 9.8% based upon a 45% common equity ratio. It is proposed that the Board continue to refrain from the use of an automatic adjustment formula for setting the allowed rate of return on the Company's rate base, in years subsequent to 2023, given current financial market conditions.

Regulatory Accounting

The Application proposes that:

1. The Board approve the calculation of depreciation expense with effect from January 1, 2022 by use of the depreciation rates as recommended in the *2019 Depreciation Study* filed with the Application, and the recovery in depreciation expense over the remaining life of the assets of an accumulated reserve variance identified in the *2019 Depreciation Study*;

2. The Board approve revisions to Newfoundland Power's GEC calculation effective January 1, 2023;

3. The Board approve, for costs incurred commencing January 1, 2021, an increase in the amortization period for customer conservation and demand management ("CDM") program costs from 7 years to 10 years, the amortization of customer electrification program costs over 10 years, and corresponding amendments to Clauses II.7 and II.9 of the Rate Stabilization Clause; and

4. The Board approve the amoritization over the 2022 to 2024 period of:

   a) an estimated $1.0 million in Consumer Advocate and Board hearing costs associated with the Application; and

   b) a forecast 2022 revenue shortfall of approximately $1,262,000.

4. Process & Related Matters

Newfoundland Power requests that the Board (i) give public notice of the Application, (ii) call 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 March 1, 2022.

The Application has been forwarded directly to Ms. Shirley Walsh, Senior Legal Counsel of Newfoundland and Labrador Hydro, and Mr. Dennis Browne, Q.C., the Consumer Advocate.

Newfoundland Power has also posted a copy of the Application on its website at www.newfoundlandpower.com. Interested parties may contact the Company directly for assistance if they have any issues accessing the website.

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

Yours truly,

Kelly Hopkins
Corporate Counsel

Enclosures

c. Shirley Walsh
Newfoundland and Labrador Hydro

Dennis Browne, QC
Consumer Advocate

Newfoundland Power Inc.
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A. EXPERT EVIDENCE

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 2022 and 2023.

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. 2 (2019), the Board ordered Newfoundland Power to file its next general rate application no later than June 1, 2021.

4. In Order No. P.U. 2 (2019), the Board ordered that the use of the automatic adjustment formula shall be suspended pending a further Order of the Board.

5. In Order No. P.U. 13 (2013), the Board approved the Conservation and Demand Management ("CDM") Cost Deferral Account and the amortization of CDM program costs over 7 years.

6. In December 2020, Newfoundland Power filed its *Electrification, Conservation and Demand Management Plan: 2021-2025* with the Board as part of its *2021 Electrification, Conservation and Demand Management Application*. That application proposed, among other matters, the establishment of an Electrification Cost Deferral Account.

7. In Order No. P.U. 3 (1995-96), the Board approved Newfoundland Power's proposal to change from the full cost method to the incremental cost method to allocate general expenses to General Expenses Capitalized ("GEC"). In February 2021, the Board

requested that Newfoundland Power include with its next general rate application a review of its methodology and cost ratios used to determine GEC. The Board requested that the review address why pension costs are included in GEC and how including pension costs in a labour loader would impact revenue requirement and customer rates. Newfoundland Power's review of its GEC is provided in *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized*.

B. Newfoundland Power Proposals:

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 2023, 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, 2022 by use of the depreciation rates as recommended in the *2019 Depreciation Study* filed with the Application, and the recovery in depreciation expense over the remaining life of the assets of an accumulated reserve variance identified in the *2019 Depreciation Study*.

10. Newfoundland Power proposes that the Board approve revisions to its GEC calculation effective January 1, 2023, for the reasons set out in the evidence filed in support of this Application.

11. Newfoundland Power proposes that the Board approve, for costs incurred commencing January 1, 2021, an increase in the amortization period for customer CDM program costs from 7 years to 10 years, the amortization of customer electrification program costs over 10 years, and corresponding amendments to Clauses II.7 and II.9 of the Rate Stabilization Clause for the reasons set out in the evidence filed in support of this Application.

12. Newfoundland Power proposes that the Board approve the amortization of the recovery of an estimated $1,000,000 in Board and Consumer Advocate costs related to the Application over a 34-month period commencing March 1, 2022 and ending December 31, 2024, as more fully described in the evidence filed in support of the Application. Newfoundland Power further proposes that any difference between actual and estimated Board and Consumer Advocate costs for rate setting purposes be recovered or rebated through the Rate Stabilization Account.

13. Newfoundland Power proposes that the Board approve the amortization of a forecast 2022 revenue shortfall of approximately $1,262,000 over a 34-month period, commencing March 1, 2022 and ending December 31, 2024.

14. Newfoundland Power proposes that the Board approve an overall average increase in current customer rates of 0.8%, with effect from March 1, 2022, based upon:

    (a) a forecast average rate base for 2022 of $1,239,558,000 and for 2023 of $1,289,405,000;

    (b) a rate of return on average rate base for 2022 of 7.19% in a range of 7.01% to 7.37% and for 2023 of 6.97% in a range of 6.79% to 7.15%; and

    (c) forecast revenue requirements from customer rates for 2022 of $715,364,000 and for 2023 of $712,803,000.

15. 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	0.8%
General Service 0-100 kW (110 kVA)	0.8%
General Service 110-1000 kVA	0.8%
General Service 1000 kVA and Over	0.8%
Street and Area Lighting	0.8%

all to be effective for service provided on and after March 1, 2022, as more fully described in the evidence filed in support of the Application.

C. Order Requested:

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

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

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

    (c) pursuant to Sections 58 and 78 of the Act, revisions to the GEC calculation as set out in paragraph 10 of the Application;

    (d) pursuant to Sections 58 and 80 of the Act, the amortizations set out in paragraphs 11, 12 and 13 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; and
(ii) rules and regulations governing service as set out in Schedule B to the Application.

all of which reflect paragraphs 14 and 15 of the Application, to be effective for service provided on and after March 1, 2022; and

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

D. Communications:

17. Communication with respect to this Application should be forwarded to the attention of Kelly C. Hopkins and Liam P. O'Brien, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador, this 27th day of May, 2021.

NEWFOUNDLAND POWER INC.

Kelly C. Hopkins and Liam P. O'Brien
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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 2022 and 2023.

AFFIDAVIT

I, Gary Murray, of St. John's in the Province of Newfoundland and Labrador, 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 27th day of May, 2021,
before me:

Barrister	**Gary Murray**

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 ....$16.10 per month
Exceeding 200 Amp Service ....$21.10 per month

Energy Charge:
All kilowatt-hours ....@ 12.298¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service ....$16.10 per month
Exceeding 200 Amp Service ....$21.10 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 ....$12.30 per month
Single Phase ....$20.30 per month
Three phase ....$32.30 per month

Demand Charge:
$9.85 per kW of billing demand in the months of December, January, February and March and $7.35 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:
First 3,500 kilowatt-hours ....@ 12.155¢ per kWh
All excess kilowatt-hours ....@ 9.145¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 21.096 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

Minimum Monthly Charge:

Unmetered ....$12.30 per month
Single Phase ....$20.30 per month
Three Phase ....$32.30 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: ....$49.76 per month

Demand Charge:
$8.27 per kVA of billing demand in the months of December, January, February and March and $5.77 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 50,000 kilowatt-hours ....@ 10.349¢ per kWh
All excess kilowatt-hours ....@ 8.356¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 21.096 cents per kWh plus the Basic Customer Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

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: ....$86.71 per month

Demand Charge:
$7.92 per kVA of billing demand in the months of December, January, February and March and $5.42 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 ....@ 9.981¢ per kWh
All excess kilowatt-hours ....@ 8.275¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 21.096 cents per kWh plus the Basic Customer Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

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)	$18.05	$19.28
150W (14,400 lumens)	22.44	-
250W (23,200 lumens)	31.84	-
400W (45,000 lumens)	44.65	-
Light Emitting Diode		
LED 100	$16.18	-
LED 150	18.16	-
LED 250	21.97	-
LED 400	25.29	-

Special poles used exclusively for lighting service*

Wood	$6.49
30' Concrete or Metal, direct buried	9.06
45' Concrete or Metal, direct buried	15.04
25' Concrete or Metal, Post Top, direct buried	6.41

Underground Wiring (per run)*

All sizes and types of fixtures	$15.28

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

General:

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

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

Availability:

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

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

Termination/Modification:

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

General:

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

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1, #2.3, and #2.4 only)

Availability:

For Customers who use generation on their Serviced Premises to offset part or all of the electrical energy requirements of the Serviced Premises. Energy generated in excess of the requirements of the Serviced Premises is permitted to be credited against the Customer's energy purchases from the Company in accordance with this rate option.

Net Metering Service is available for any Serviced Premises that is supplied from the Company's distribution system, is billed under one of the Company's metered service rates, and which has generation electrically connected to it that meets the requirements of these provisions. Net Metering Service is not available for un-metered service accounts.

In order to avail of the Net Metering Service Option, Customers must submit a completed Net Metering Service Application to the Company demonstrating the Customer's eligibility for Net Metering Service.

Availability of the Net Metering Service Option will be closed once the provincial aggregate generating capacity for Net Metering Service of 5.0 MW has been met.

Customers that avail of the Net Metering Service Option must maintain compliance with all requirements of this Option. The Company shall have the right to verify compliance through inspection or testing.

Metering:

Net Metering Service will ordinarily be metered using a Company-supplied single meter capable of registering the flow of electrical energy in two directions. The meter will separately capture both the energy supplied to the Customer by the Company and the energy supplied to the Company by the Customer.

At the Company's option, the output of the Customer's generation may be metered separately. In that case, the Customer shall provide the Company with the access necessary to install and maintain the required metering equipment.

The Customer shall pay all costs to upgrade the metering equipment for Net Metering Service if the existing electrical meter at the Serviced Premises is not capable of safely and reliably measuring both the energy supplied to the Customer by the Company and the energy supplied to the Company by the Customer.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1, #2.3, and #2.4 only)

Billing:

Each account availing of Net Metering Service will be billed on the rate normally applicable to the Customer's class of Service.

The Customer's net monthly bill will be determined by deducting the Customer Generation Credit from the total of all charges for Service. The Customer Generation Credit equals the Generation Energy Credit, in kilowatt-hours ("kWh") multiplied by the rate applicable to the Customer's class of Service during the billing month.

The "Generation Energy Credit" is the sum of the kWh energy supplied by the Customer to the Company during the billing month plus Banked Energy Credits. The Generation Energy Credit for a billing month shall not exceed the energy supplied by the Company to the Customer during that month.

"Banked Energy Credits" are the amount of kWh energy supplied by the Customer to the Company that exceeds the kWh energy supplied by the Company to the Customer. Banked Energy Credits in excess of those used to calculate the Generation Energy Credit for a billing month will be carried forward to the following month.

The balance of the Customer's Banked Energy Credits carried forward will be settled annually by means of a credit on the Customer's bill for the Annual Review Billing Month. The Annual Review Billing Month will be determined by the Customer, in consultation with the Company, during the process of implementing Net Metering Service. Settlement of Banked Energy Credits will be computed based upon the then-current 2nd block energy charge in Newfoundland and Labrador Hydro's Utility Rate applicable to service provided to the Company.

Whenever a Customer's participation in the Net Metering Service Option is discontinued, any unused Banked Energy Credits will be settled with a credit on the Customer's next bill.

All customers must pay Harmonized Sales Tax (HST) on the energy supplied by the Company to the Customer during the billing month. If a Customer availing of Net Metering Service is required by law to collect HST on the energy they supply to the Company, the Company will pay HST to the Customer based on the amount of the Customer Generation Credit. It is the Customer's responsibility to notify the Company in writing if they are required to collect HST on the energy they supply to the Company.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1, #2.3, and #2.4 only)

Special Conditions:

Special conditions in this clause do not supersede, modify or nullify the conditions accompanying the metered rate schedules applicable to the Customer's class of Service.

To avail of Net Metering Service, a single Customer must own and maintain responsibility for the Serviced Premises, the generation and the electrical facilities connecting it to the Company's distribution system.

To qualify for Net Metering Service, the Customer's generation must meet the following requirements:

i) be designed not to exceed the annual energy requirements of the buildings and facilities metered together on the Serviced Premises;
ii) have a manufacturer's nameplate capacity rating totaling not more than 100 kW, except where a lower rating is stipulated by the Company for technical reasons;
iii) be electrically connected through Customer-owned electrical facilities to the Serviced Premises to which Net Metering Service is being provided;
iv) produce electrical energy from a renewable energy source, including wind, solar, photovoltaic, geothermal, tidal, wave, biomass energy or other renewable energy sources that may be approved by the Company on a case-by-case basis; and
v) meet all applicable safety and performance standards established by the Canadian Electrical Code, the Public Safety Act and the Company's Interconnection Requirements.

All Customer-owned wiring, equipment and devices associated with generation utilized for Net Metering Service shall conform to the Company's interconnection requirements.

The Customer will retain the rights to any renewable energy credits or greenhouse gas-related credits arising from the use of renewable energy sources to generate electricity in accordance with this Option.

A Customer availing of Net Metering Service is responsible for all costs associated with their own facilities. The Customer shall also be required to pay all costs incurred by the Company to modify the utility supply for the provision of Net Metering Service, and for necessary engineering or technical studies required in connection with the provision of Net Metering Service to the Customer.

The approval of an application for Net Metering Service will be subject to the applicant entering into a Net Metering Interconnection Agreement with the Company.

If an applicant approved for Net Metering Service does not proceed with operation of its generation in accordance with its approval within two years from the date of the Company's approval of the application, the approval will be rescinded.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1, #2.3, and #2.4 only)

Approval of Net Metering Service may be revoked if a Customer is found to be in violation of provisions of the Company’s Rules and Regulations.

If participation in the Net Metering Service Option is discontinued, the Customer must re-apply to the Company to avail of the Net Metering Service Option.

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* R.S.N.L. 1990, c. P-47 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.

NEWFOUNDLAND POWER INC.

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(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).
- (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.

NEWFOUNDLAND POWER INC.

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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.

NEWFOUNDLAND POWER INC.

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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.

NEWFOUNDLAND POWER INC.

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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.

(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.

NEWFOUNDLAND POWER INC.

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(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.

(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.

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(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%.

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.

NEWFOUNDLAND POWER INC.

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(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.

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.

NEWFOUNDLAND POWER INC.

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(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.

(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

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(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.

(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.

NEWFOUNDLAND POWER INC.

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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.

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.

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(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.

(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.

NEWFOUNDLAND POWER INC.

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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.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

The Company shall include a rate stabilization adjustment in its rates. This adjustment shall reflect the accumulated balance in the Company's Rate Stabilization Account ("RSA") and any change in the rates charged to the Company by Newfoundland and Labrador Hydro ("Hydro") as a result of the operation of its Rate Stabilization Plan ("RSP"), CDM Cost Recovery Adjustment and 2017 GRA Cost Recovery Rider (collectively, "Hydro's Rate Adjustments").

I. RATE STABILIZATION ADJUSTMENT ("A")

The Rate Stabilization Adjustment ("A") shall be calculated as the total of the Recovery Adjustment Factor, the Fuel Rider Adjustment and the Hydro 2017 GRA Cost Recovery Adjustment.

The Recovery Adjustment Factor shall be recalculated annually, effective the first day of July in each year, to amortize over the following twelve (12) month period the annual plan recovery amount designated to be billed by Hydro to the Company, and the balance in the Company's RSA.

The Recovery Adjustment Factor expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{B1 + B2 + C}{D}$$

Where:

B1 = the annual plan recovery amount designated to be billed by Hydro during the next twelve (12) months commencing July 1 as a result of the operation of Hydro's RSP.

B2 = the annual plan recovery amount designated to be billed by Hydro during the next twelve (12) months commencing July 1 as a result of the operation of Hydro's CDM Cost Recovery Adjustment.

C = the balance in the Company's RSA as of March 31st of the current year.

D = the total kilowatt-hours sold by the Company for the 12 months ending March 31st of the current year.

The Fuel Rider Adjustment shall be recalculated annually, effective the first day of July in each year, to reflect changes in the RSP fuel rider applicable to Newfoundland Power. The Fuel Rider Adjustment expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{E}{D} \times F$$

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

I. RATE STABILIZATION ADJUSTMENT ("A") (Cont'd)

Where:

D = corresponds to the D above.

E = the total kilowatt-hours of energy (including secondary energy) sold to the Company by Hydro during the 12 months ending March 31 of the current year.

F = the fuel rider designated to be charged to Newfoundland Power through Hydro's RSP.

The Hydro 2017 GRA Cost Recovery Adjustment Factor shall be in effect from October 1, 2019 to May 31, 2021 and shall be calculated to the nearest 0.001 cent as follows:

$$\frac{M}{D}$$

Where:

M = $892,219 *times* 12 months (for 2020, *times* 11 months).
D = corresponds to the D above.

The Rate Stabilization Adjustment ("A") shall be recalculated and be applied as of the effective date of a new wholesale mill rate by Hydro, by resetting the Fuel Rider Adjustment included in the Rate Stabilization Adjustment to zero.

II. RATE STABILIZATION ACCOUNT ("RSA")

The Company shall maintain a RSA which shall be increased or reduced by the following amounts expressed in dollars:

1. At the end of each month the RSA shall be:

   (i) increased (reduced) by the amount actually charged (credited) to the Company by Hydro during the month as the result of Hydro's Rate Adjustments.

   (ii) increased (reduced) by the excess cost of fuel used by the Company during the month calculated as follows:

$$(G/H - P) \quad x \quad H$$

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

Where:

G = the cost in dollars of fuel and additives used during the month in the Company's thermal plants to generate electricity other than that generated at the request of Hydro.

H = the net kilowatt-hours generated in the month in the Company's thermal plants other than electricity generated at the request of Hydro.

P = the 2nd block base rate in dollars per kilowatt-hour paid during the month by the Company to Hydro for firm energy.

(iii) reduced by the price differential of firmed-up secondary energy calculated as follows:

$$\mathbf{(P - J) \times K}$$

Where:

J = the price in dollars per kilowatt-hour paid by the Company to Hydro during the month for secondary energy supplied by Deer Lake Power and delivered as firm energy to the Company.

K = the kilowatt-hours of such secondary energy supplied to the Company during the month.

P = corresponds to P above.

(iv) reduced (increased) by the amount billed by the Company during the month as the result of the operation of the Rate Stabilization Clause calculated as follows:

$$\frac{L \times A}{100}$$

Where:

L = the total kilowatt-hours sold by the Company during the month.

A = the Rate Stabilization Adjustment in effect during the month expressed in cents per kilowatt-hour.

(v) increased (reduced) by an interest charge (credit) on the balance in the RSA at the beginning of the month, at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base.

2. On the 31st of December in each year, the RSA shall be increased (reduced) by the amount that the Company billed customers under the Municipal Tax Clause for the calendar year is less (or greater) than the amount of municipal taxes paid for that year.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

3. The annual kilowatt-hours used in calculating the Rate Stabilization Adjustment to the monthly street lighting rates are as follows:

	Fixture Size (watts)			
	100	150	250	400
High Pressure Sodium	454	714	1,260	1,953
	Fixture Type			
	LED 100	LED 150	LED 250	LED 400
Light Emitting Diode	218	336	475	664

4. On December 31, 2019, the RSA shall be reduced (increased) by the amount that the increase in the Company's revenue for the year resulting from the change in base rates attributable to the flow through of Hydro's wholesale rate change, effective October 1, 2019, is greater (or less) than the amount of the increase in the Company's purchased power expense for the year resulting from the change in the base rate charged by Hydro effective October 1, 2019.

   The methodology to calculate the RSA adjustment at December 31, 2019 is as follows:

Calculation of increase in Revenue:	
2019 Revenue with Flow-through (Q)	$ -
2019 Revenue without Flow-through (R)	$ -
Increase in Revenue (S = Q – R)	$ -
Calculation of increase in Purchased Power Expense:	
2019 Purchased Power Expense with Hydro Increase (T)	$ -
2019 Purchased Power Expense without Hydro Increase (U)	$ -
Increase in Purchased Power Expense (V = T – U)	$ -
Adjustment to Rate Stabilization Account (W = S – V)	$ -

   Where:

   Q = Normalized revenue from base rates effective October 1, 2019.

   R = Normalized revenue from base rates determined based on rates effective March 1, 2019.

   T = Normalized purchased power expense from Hydro's wholesale rate effective October 1, 2019 (not including Hydro's Rate Adjustments).

   U = Normalized purchased power expense determined based on Hydro's wholesale rate effective July 1, 2018 (not including Hydro's Rate Adjustments).

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

5. On December 31st of each year from 2008 until further order of the Board, the Rate Stabilization Account (RSA) shall be increased (reduced) by the Energy Supply Cost Variance.

   This Energy Supply Cost Variance identifies the change in purchased power cost that is related to the difference between purchasing energy at the 2nd block energy charge in the wholesale rate and the test year energy supply cost reflected in customer rates.

   The Energy Supply Cost Variance expressed in dollars shall be calculated as follows:

$$\frac{(A - B) \times (C - D)}{100}$$

   Where:

   A = the wholesale rate 2nd block charge per kWh.

   B = the test year energy supply cost per kWh determined by applying the wholesale energy rate to the test year energy purchases and expressed in ¢ per kWh.

   C = the weather normalized annual purchases in kWh.

   D = the test year annual purchases in kWh.

6. The RSA shall be adjusted by any other amount as ordered by the Board.

7. On March 31st of each year, the Rate Stabilization Account shall be increased on a before tax basis, by the CDM Cost Recovery Transfer.

   The CDM Cost Recovery Transfer, expressed in dollars, will be calculated to provide for the recovery of costs charged annually to the Conservation and Demand Management Cost Deferral Account (the "CDM Cost Deferral"), commencing in the year following the year in which the CDM Cost Deferral is charged to the CDM Cost Deferral Account. Beginning January 1, 2021, annual charges to the CDM Cost Deferral will be recovered over 10 years. Annual charges to the CDM Cost Deferral up to December 31, 2020, will continue to be recovered over 7 years in accordance with Order. No. P.U. 13 (2013).

   The CDM Cost Deferral Account will identify the year in which each CDM Cost Deferral was incurred.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

The CDM Cost Recovery Transfer for each year will be determined as follows:

A + B

Where:

A = the sum of individual amounts representing 1/7th of each CDM Cost Deferral up to December 31, 2020, which individual amounts shall be included in the CDM Cost Recovery Transfer for 7 years in which the CDM Cost Deferral was recorded.

B = the sum of individual amounts representing 1/10th of each CDM Cost Deferral, beginning January 1, 2021, which individual amounts shall be included in the CDM Cost Recovery Transfer for 10 years following the year in which the CDM Cost Deferral was recorded.

8. On March 31st of each year, beginning in 2013, the Rate Stabilization Account shall be increased (reduced), on a before tax basis, by the balance in the Weather Normalization Reserve accrued in the previous year.

9. On March 31st of each year, beginning in 2022, the Rate Stabilization Account shall be increased on a before tax basis, by the Electrification Cost Recovery Transfer.

   The Electrification Cost Recovery Transfer, expressed in dollars, will be calculated to provide for the recovery of costs charged annually to the Electrification Cost Deferral Account over a 10-year period, commencing in the year following the year in which the Electrification Cost Deferral is charged to the Electrification Cost Deferral Account.

   The Electrification Cost Deferral Account will identify the year in which each Electrification Cost Deferral was incurred.

   The Electrification Cost Recovery Transfer for each year will be the sum of individual amounts representing 1/10th of each Electrification Cost Deferral, which individual amounts shall be included in the Electrification Cost Recovery Transfer for 10 years following the year in which the Electrification Cost Deferral was recorded.

III. RATE CHANGES

The energy charges in each rate classification shall be adjusted as required to reflect the changes in the Rate Stabilization Adjustment. The new energy charges shall be determined by subtracting the previous Rate Stabilization Adjustment from the previous energy charges and adding the new Rate Stabilization Adjustment. The new energy charges shall apply to all bills based on consumption on and after the effective date of the adjustment.

NEWFOUNDLAND POWER INC.

MUNICIPAL TAX CLAUSE

I. MUNICIPAL TAX ADJUSTMENT ("MTA")

The Company shall include a MTA in its rates to reflect taxes charged to the Company by municipalities.

A MTA factor shall be calculated annually, effective the first day of July in each year, to collect over the following twelve (12) month period, an amount to cover municipal taxes. The MTA factor rounded to the nearest fifth decimal shall be calculated as follows:

$$\frac{X}{Y} + 1.00000$$

Where:

X = the amount of all municipal taxes paid by the Company in the previous calendar year.

Y = the amount of revenue earned by the Company in the previous calendar year less the amount collected by the Company under the Municipal Tax Clause in that year.

The MTA factor shall apply to all charges in all rate descriptions. These charges shall be adjusted annually effective the first day of July in each year to reflect changes in the MTA factor. The new charges rounded to the nearest significant number expressed in the rate descriptions shall be determined by multiplying each charge by the MTA factor. The new charges shall apply to all bills based on consumption on and after the first day of July.

The MTA factor shall be applied after application of the Rate Stabilization Adjustment.

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

Table 1-1 provides the number of customers served by Newfoundland Power and the Company's annual weather-adjusted energy sales from 2019 to 2023F.

Table 1-1:
Customers and Sales
2019 to 2023F

	2019	**2020**	**2021F**	**2022F**	**2023F**
Customers	269,045	270,285	271,298	272,253	273,165
Sales (GWh)	5,847	5,729	5,720	5,699	5,662

The number of customers served by Newfoundland Power is forecast to increase by approximately 0.4% per year from 2019 to 2023. Annual weather-adjusted energy sales are forecast to decrease by approximately 0.8% per year over the same period.

Domestic service customers account for the largest percentage of Newfoundland Power's sales. Sales to domestic service customers are forecast to decline by approximately 1.0% annually from

2019 to 2023. Sales to general service customers are forecast to decline by approximately 0.3% annually over the same period.

This forecast decline in energy sales reflects the challenging economic conditions in Newfoundland Power's service territory. Housing starts in the province are forecast to decline, unemployment is expected to remain high, and Provincial Government spending is expected to be constrained as the province addresses its debt obligations and annual fiscal deficits.

The forecast decline in energy sales also reflects the penetration of heat pumps among the Company's customers. The penetration of heat pumps among Newfoundland Power's customers increased from approximately 4% in 2014 to approximately 18% in 2020.

Energy sales in 2020 were affected by public health measures introduced by the Provincial Government to manage the COVID-19 pandemic. These public health measures have continued into 2021, but are expected to subside throughout the year as the Provincial Government implements its vaccination plans. Energy sales in 2022 and 2023 are not expected to be affected by public health measures related to the COVID-19 pandemic.

Newfoundland Power's long-term growth outlook is uncertain. This uncertainty reflects a weak economic outlook for the province and potential increases in the cost of electricity following the commissioning of Nalcor Energy's Muskrat Falls Project.

1.1.2 Balancing Costs and Service

Newfoundland Power is responsible for serving approximately 87% of all electricity customers in Newfoundland and Labrador. The Company manages its operations in a manner responsive to customers' service expectations.

Quarterly surveys indicate the 2 most important issues to Newfoundland Power's customers are service reliability and price. Balancing the cost and quality of service provided to customers requires efficiency in the Company's operations.

Efficient utility operations is consistent with the provincial power policy. The provincial power policy requires Newfoundland Power to manage its operations in a manner that results in power being delivered to customers at the lowest possible cost consistent with reliable service.[1]

Reliable service delivery and sound cost management are therefore cornerstones of the Company's operations.

1.1.3 Newfoundland Power's Performance

Customers have indicated a reasonable level of satisfaction with Newfoundland Power's service delivery over the last decade.

The Company's electrical system performs reliably.

[1] Section 3(b)(iii) of the *Electrical Power Control Act, 1994.*

The average duration of customer outages has been approximately ½ the Canadian average over the last 10 years. The average frequency of customer outages has been consistent with the Canadian average over the same period.

The Company's operations are focused on maintaining overall levels of service reliability for customers. Newfoundland Power maintains the reliability of its service delivery through a combination of routine inspections and maintenance, stable and predictable capital investments, and a timely response to customer outages.

Newfoundland Power demonstrates sound cost management.

Newfoundland Power's gross operating cost per customer was reduced by approximately 16% on an inflation-adjusted basis over the last decade. The effective use of technology has been a primary means through which the Company has improved its operating efficiency.

For example, the Company's customer service costs were reduced by approximately 18% between 2011 and 2020. This cost reduction was achieved while serving approximately 23,000 more customers and responding to over double the number of customer enquiries. This service efficiency was supported by various technology-driven initiatives, including Automated Meter Reading.

The efficiency of Newfoundland Power's operations can be observed in the Company's response to widespread customer outages. For example, over 100,000 customers experienced outages in January 2020 following a severe blizzard. During this event, the Company's Outage

Management System automatically assessed approximately 5,000 customer outage reports, the High Volume Call Answering system automatically resolved approximately 18,000 customer enquiries, and electrical system automation avoided approximately 3.5 million customer outage minutes without the assistance of field crews.

The Company continues to focus on the delivery of reliable service to customers at least cost.

Labour costs account for over ½ of Newfoundland Power's annual operating costs. Operating labour costs are forecast to increase by approximately 2.1% annually from 2019 to 2023. This is approximately 1% less than the Company's annual labour inflation over the same period.

Newfoundland Power introduced LED Street and Area Lighting as a service option for its customers in 2019. LED street lights offer customers lower rates for a more reliable service. The Company is executing a plan to provide all street and area lighting customers with LED street lights by 2026.

Newfoundland Power and Hydro have jointly delivered conservation and demand management ("CDM") programs to customers since 2009. The utilities have developed a new plan to deliver customer programs from 2021 to 2025. The new plan continues longstanding CDM programs and introduces customer electrification programs. Both CDM and electrification programs reduce overall costs to customers. Electrification programs will provide a rate mitigating benefit to customers over the longer term.

1.1.4 Provincial Electricity Sector

The commissioning of Nalcor Energy's Muskrat Falls Project will be a transformative event for the provincial electricity sector and remains a concern for Newfoundland Power's customers.

The cost of the Muskrat Falls Project is substantial compared to the province's existing electrical system. The total capital cost of the project is currently estimated at approximately $13.1 billion. This is over 3 times the book value of the province's existing electrical system.

The Provincial Government issued a Reference to the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") in 2018 to assess options available to mitigate customer rate increases associated with the Muskrat Falls Project. The Board assessed options to reduce costs to customers and increase revenues.

The Board determined that, even if all recommended sources of rate mitigation are implemented, customer rates are still forecast to increase by approximately 50%.

The Board found that there may be additional rate mitigation potential associated with Muskrat Falls Project financing. In February 2020, the Provincial Government entered into negotiations with the Federal Government to undertake a financial restructuring of the project.

The reliability of the Muskrat Falls Project is currently under review by the Board. Upon commissioning of the project, the largest source of electricity supply for Newfoundland Power's customers will be located off the island, approximately 1,100 kilometres from the province's load centre on the Avalon Peninsula.

The Muskrat Falls Project will supply the Company's customers by way of the Labrador-Island Link. The reliability of the Labrador-Island Link is among the issues under review by the Board. The Labrador-Island Link experienced damage due to ice accumulation and other equipment failures in 2021. Substantial time was required to undertake the necessary repairs.

The adequacy of generation resources on the Island Interconnected System is also under review by the Board. At the time of sanctioning the Muskrat Falls Project in 2012, it was anticipated that commissioning of the project would enable the retirement of Hydro's Holyrood Thermal Generating Station. The potential retirement of Holyrood is now uncertain.

Any additional investments to ensure the reliability of supply to customers on the island could be expected to place upwards pressure on customer rates.

1.1.5 Risk and Return

In this Application, the Board will consider an appropriate capital structure for ratemaking purposes, an appropriate return on common equity invested in the Company, and the use of an automatic adjustment formula to establish Newfoundland Power's cost of equity following the 2023 test year.

In 2018, Newfoundland Power observed that certain business risks had become more pronounced since its last general rate application. The provincial economy had deteriorated, energy sales had declined, and the cost of the Muskrat Falls Project had increased.

The Company's business risks have not materially changed since 2018. The province continues to lag behind Canada across key economic indicators. Energy sales in 2023 are forecast to be 3.2% less than energy sales in 2019. The Muskrat Falls Project continues to pose a risk to the delivery of reliable service to customers at least cost.

Newfoundland Power's business risks also continue to be defined by longstanding factors. These factors include weak service territory demographics, harsh operating conditions, the Company's small size and its limited cost flexibility.

Expert evidence filed with this Application indicates that Newfoundland Power has above-average business risk in comparison to other Canadian utilities.

1.2 APPLICATION PROPOSALS

1.2.1 2022 and 2023 Revenue Requirements

In this Application, Newfoundland Power is proposing an average increase in current customer rates of approximately 0.8%, effective March 1, 2022. This rate increase is primarily the result of 3 changes in the Company's cost of service.

The first change reflects a proposed increase in the Company's return on equity. Expert evidence filed with this Application recommends a fair return on equity for Newfoundland Power in 2022 and 2023 is 9.8% on a common equity ratio of 45%. This return on equity represents a 1.5% increase in the revenue required from customer rates.

The second change relates to variations in Newfoundland Power's costs since its last general rate application. This includes the cost of continued investment in the electrical system, increased operating costs and the effects of amortizations proposed in this Application. The net result of these changes is a 2.0% increase in the revenue required from customer rates.

The third change relates to the recovery of wholesale supply costs from forecast energy sales. A general rate application requires forecast supply costs to be reconciled with forecast revenue from energy sales during the test period. Rebalancing 2022 and 2023 supply costs and revenue from energy sales results in a 2.7% decrease in the revenue required from customer rates.

The Company proposes to apply the average rate increase of 0.8% equally to all customer classes. Uniform increases in customer rates will maintain class revenue-to-cost ratios within a range of 90% to 110%.

1.2.2 Other Proposals

The Application proposes the Board continue the suspension of an automatic adjustment formula to establish Newfoundland Power's annual return on equity following the 2023 test year. Long Canada bond yields form the basis of the formula's operation. There has been no appreciable change in long Canada bond yields since Newfoundland Power's last general rate application. Accordingly, current circumstances do not warrant reinstatement of the formula.

SECTION 2: CUSTOMER OPERATIONS

2.1 OVERVIEW

Newfoundland Power provides service in the least-cost manner responsive to customers' expectations.

The Company's customer service delivery is efficient and responsive to customers. Customer service costs were reduced by approximately 18% from 2011 to 2020. This cost reduction was achieved while serving more customers and responding to more customer enquiries. While costs declined, customer satisfaction remained reasonably consistent.

A new plan has been developed to guide customer program delivery from 2021 to 2025. The plan introduces customer electrification programs and continues longstanding CDM programs. Both electrification and CDM programs will reduce overall costs to customers. Electrification programs will provide a rate mitigating benefit for customers over the longer term.

Newfoundland Power's electrical system operates reliably. The average duration of customer outages has been approximately ½ the Canadian average over the last decade. The frequency of customer outages has been consistent with the Canadian average.

The Company is responsive to customer outages and customer-driven work requests. Newfoundland Power's average restoration time for unscheduled outages has been approximately ½ the Canadian average since 2010. Target response times for completing new service connections have been consistently met over the last 5 years.

Technology-driven initiatives have allowed Newfoundland Power to balance the cost and quality of service provided to customers. The Company's operating costs per customer were reduced by approximately 16% on an inflation-adjusted basis over the last decade.

Gross operating costs are forecast to increase by approximately 2.8% per year from 2019 to 2023. Operating labour costs are forecast to increase by 2.1% per year over the same period. This increase in labour costs is less than the Company's labour rate inflation and reflects a continued focus on operating efficiency.

Newfoundland Power continues to invest in its electrical system to serve new customers and replace deteriorated and defective equipment. These investments are consistent with the delivery of reliable service to customers at least cost.

2.2 CUSTOMER SERVICE

2.2.1 Customer Service Delivery

Newfoundland Power expects to serve approximately 273,000 customers by 2023.

Customers primarily contact the Company to obtain information related to their accounts, outages and available programs and services. Delivering responsive customer service requires effectively managing customers' enquiries.

Table 2-1 provides the number of customer enquiries received annually from 2016 to 2020.

Table 2-1:
Customer Enquiries
2016 to 2020
(000s)

	2016	**2017[1]**	**2018**	**2019**	**2020**
Telephone	418	580	470	458	433
Email	72	124	130	109	132
Website	1,748	2,843	1,823	1,771	2,193
Total	**2,238**	**3,547**	**2,423**	**2,338**	**2,758**

The number of enquiries received from customers exceeded 2.7 million in 2020. This was approximately 23% higher than the number of customer enquiries received in 2016.[2]

The increase in customer enquiries is primarily observed in customers' use of digital communication channels.

Email enquiries from customers nearly doubled from 2016 to 2020.[3] Customers email the Company to obtain information on account balances, payment arrangements and requests for field work, among other requests.

[1] The high number of customer enquiries received in 2017 resulted from the delivery of the Rate Stabilization Plan ("RSP") Refund. Delivery of the RSP Refund accounted for approximately 823,000 enquiries in 2017, or 23% of all enquiries received that year.

[2] (2,758,000 – 2,238,000) / 2,238,000 = 0.23, or 23%.

[3] 132,000 / 72,000 = 1.8.

Visits to Newfoundland Power's website increased by approximately ¼ from 2016 to 2020.[4] The website is currently the most used communication channel among customers. In 2020, approximately 80% of visits to the website were driven by customers accessing information on their accounts and outages.[5]

Customers' increased use of digital communication channels is consistent with current industry trends.[6] Newfoundland Power has continued to enhance the digital communication channels available to its customers.

The customer website was enhanced in 2019 to provide customers with the option of reporting outages online. The website was also enhanced to provide more accurate, real-time information to customers on the status of outages from the Company's new Outage Management System.[7]

Website self-service options were enhanced for customers in 2020. Customers can now monitor and make changes to their Equal Payment Plan ("EPP") via the website.[8] Customers can also now enroll in the Automated Payment Plan ("APP") entirely via the website, rather than by email

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[4] (2,193,000 - 1,748,000) / 1,748,000 = 0.25, or 25%.

[5] Newfoundland Power's website includes dozens of distinct pages with various information for customers. The 2.2 million visits to the website in 2020 generated approximately 6 million page views. Approximately 3.5 million views were on account-related pages and 1.4 million views were on outage-related pages ((3.5 million + 1.4 million) / 6 million = 0.82, or 82%).

[6] McKinsey & Company notes: "*In addition to customers being increasingly open to engaging with companies over email, the web, self-service applications, and mobile devices, those digital interactions account for a growing share of all customer-initiated contact*." See *Service industries can fuel growth by making digital customer experiences a priority*, April 30, 2020, page 3.

[7] The Outage Management System and Geographic Information System are configured to automatically provide updates to the customer website on the status of customer outages, including the location of outages via the outage map. For more information on the Outage Management System, see *Section 2.3.3 Field Response.*

[8] The EPP averages customers' monthly bill payments over 12 months. Customers now have access to their EPP payment progress throughout the year and have the ability to modify their monthly payments based on guidance and parameters established on the website. Prior to this enhancement, customers were required to contact the Company to obtain detailed information on their EPP progress or to make changes to their monthly payments.

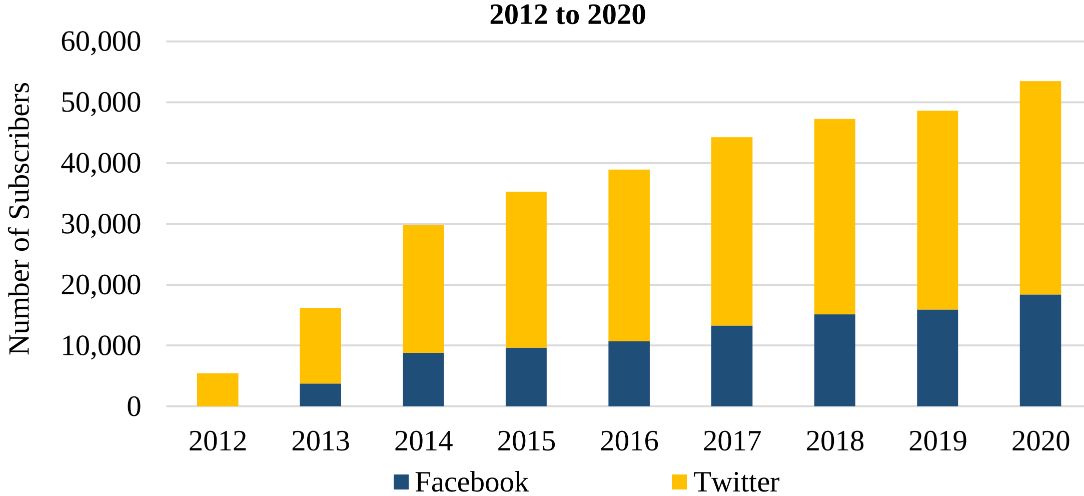
or mail.[9] At year-end 2020, approximately 44,000 customers were enrolled in the EPP and approximately 47,000 customers were enrolled in the APP.

The customer website will be further enhanced in 2021 with the implementation of an online chat option.[10] The online chat option will allow customers to communicate directly with Customer Service Representatives via the website.

Newfoundland Power continues to use social media to share information with its customers, including information on outages and available programs and services.

Figure 2-1 shows the number of subscribers to Newfoundland Power's social media channels since implementation in 2012.

Figure 2-1:
Social Media Subscribers
2012 to 2020



[9] The APP automatically deducts customers' monthly bill payments from their bank accounts. Customers now have the option to submit their banking information via a secure online form. Prior to this enhancement, customers were required to download a form and provide the completed form with proof of banking information via mail or email.

[10] The implementation of an online chat option was outlined in Newfoundland Power's *2020 Capital Budget Application* (see *Report 6.1 2020 Application Enhancements*), which was approved in Order No. P.U. 5 (2020).

There has been a tenfold increase in the number of subscribers to Newfoundland Power's social media channels since 2012.[11] Combined, the Company's Facebook and Twitter accounts had over 53,000 subscribers in 2020. Customers' increased use of social media is consistent with their growing preference for digital communication.

2.2.2 Customer Service Efficiency

Newfoundland Power reduced its customer service costs by approximately 18% from 2011 to 2020.[12] This cost reduction was achieved while serving approximately 23,000 more customers and responding to more than double the number of customer enquiries.[13]

The Company maintains the efficiency of its customer service delivery primarily through the effective use of technology.

Newfoundland Power implemented a new High-Volume Call Answering ("HVCA") system in 2019.[14] The HVCA system provides an automated response to customers' outage-related enquiries. For example, the new system allows customers to report an outage via the telephone without the assistance of a Customer Service Representative.[15]

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[11] Newfoundland Power's social media channels had approximately 5,500 subscribers in 2012 and approximately 53,400 subscribers in 2020 (53,400 / 5,500 = 9.7).

[12] Newfoundland Power's customer service costs were approximately $9.1 million in 2011 and $7.5 million in 2020 (($7.5 million - $9.1 million) / $9.1 million = -0.18, or -18%).

[13] The Company served approximately 247,000 customers in 2011 and 270,000 customers in 2020 (270,000 – 247,000 = 23,000). The Company received approximately 1.1 million customer enquiries in 2011, compared to approximately 2.8 million enquiries in 2020 (2.8 million / 1.1 million = 2.5).

[14] Implementation of the HVCA system was outlined in Newfoundland Power's *2019 Capital Budget Application* (see *Report 6.2 2019 System Upgrades*, pages 2-3) and was approved in Order No. P.U. 35 (2018).

[15] The new HVCA system is integrated with the Company's Outage Management System. This integration provides more accurate outage-related information to customers using the HVCA system.

The HVCA system provides an efficient response to customers' enquiries. The cost of an enquiry resolved by the HVCA system is approximately 67¢ per call.[16] This is substantially less than the cost of an enquiry resolved by a Customer Service Representative.[17]

The benefits of the HVCA system are most pronounced during widespread outages, when the volume of customer calls is highest. For example, widespread outages occurred in January 2020 following a severe blizzard. Newfoundland Power received over 25,000 customer calls during this event. Approximately 72% of these calls were resolved via the HVCA system.[18]

The Company began deploying Automated Meter Reading ("AMR") meters in 2013.[19] Virtually all meters in Newfoundland Power's service territory were automated by year-end 2017. The Company has continued to optimize its meter reading routes to ensure the 259,000 customer meters throughout its service territory are efficiently read.[20]

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[16] This includes system usage, maintenance and support costs.

[17] The cost of a call resolved by a Customer Service Representative is approximately $10.60 per call. This includes labour costs, technology maintenance costs and long distance charges.

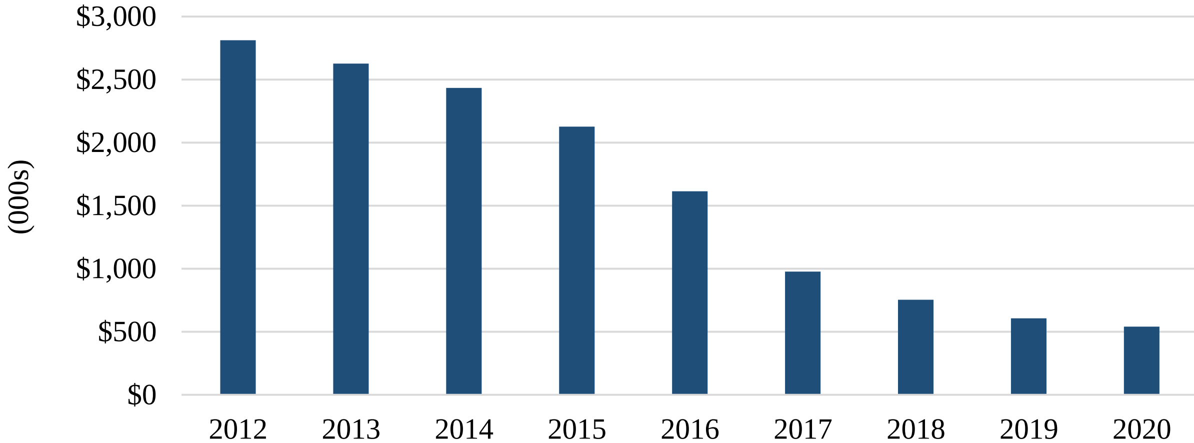
[18] From January 16, 2020 to January 23, 2020, the HVCA system responded to approximately 18,000 calls (18,000 / 25,000 = 0.72, or 72%).

[19] The Company's accelerated deployment of AMR meters is described in Newfoundland Power's *2016 Capital Budget Application, Report 4.4: 2016 Metering Strategy*.

[20] Newfoundland Power maintained 426 meter reading routes in 2015, 143 meter reading routes in 2017, and 78 meter reading routes in 2020.

Figure 2-2 shows the Company's meter reading operating costs from 2012 to 2020.

Figure 2-2:
Meter Reading Operating Costs
2012 to 2020



Newfoundland Power's meter reading operating costs were reduced by approximately 81% from $2.8 million in 2012 to $540,000 in 2020.[21]

Newfoundland Power introduced LED Street and Area Lighting as a service option for its customers in 2019.[22] LED street lights provide customers with lower rates for a more reliable service. In comparison to high-pressure sodium street lights, LED street lights provide customers with lower rates of between 9% to 39%, depending on the lighting output required.

Approximately 1,500 Street and Area Lighting customers were provided with LED street lights at year-end 2020.[23] Newfoundland Power is executing a plan to provide all Street and Area Lighting customers with LED street lights by year-end 2026.[24]

[21] ($540,000 - $2,800,000) / $2,800,000 = -0.81, or -81%.
[22] LED Street and Area Lighting was approved in Order No. P.U. 2 (2019).
[23] At year-end 2020, approximately 6,000 LED street lights provided service to approximately 1,500 customers.
[24] See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan.*

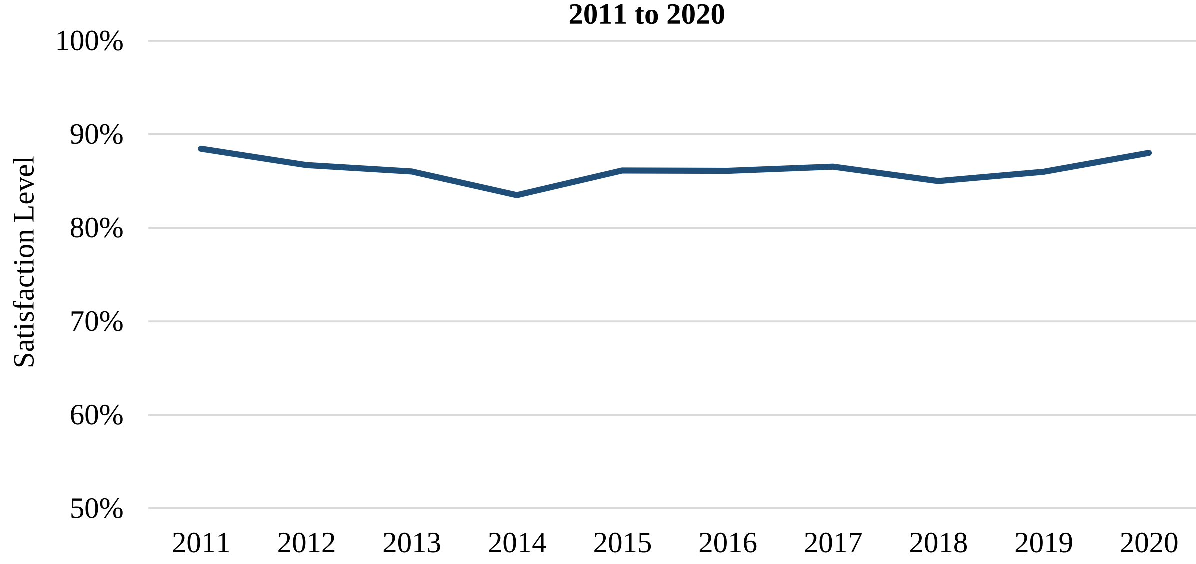
Newfoundland Power's Customer Service System has been integral to the delivery of efficient and responsive customer service since 1993.[25] The Company is executing a plan to replace this system by 2023 following 30 years of operation.[26] Replacement of this system will ensure customers continue to be served in an efficient and responsive manner over the longer term.[27]

2.2.3 Customer Satisfaction

Customers' satisfaction with Newfoundland Power's service delivery is assessed through quarterly surveys. Approximately 1,800 customers are surveyed each quarter.

Figure 2-3 shows customers' overall satisfaction with Newfoundland Power's service delivery from 2011 to 2020.

Figure 2-3:
Customer Satisfaction
2011 to 2020



[25] The Customer Service System supports all essential customer service functions, including program and service delivery, account management and billing, and the management of customer communications.
[26] The Board approved the Customer Service System Replacement Project in Order No. P.U. 12 (2021).
[27] See Newfoundland Power's *2021 Capital Budget Application, Volume 1, Customer Service Continuity Plan.*

Customers' overall satisfaction with Newfoundland Power's service delivery was approximately 88% in 2020. This is reasonably consistent with customers' average level of satisfaction over the last decade.[28]

Customers' satisfaction with the Company's service delivery was lowest in 2014, which was marked by widespread customer outages due to a loss of supply.[29] This highlights the importance of service reliability to Newfoundland Power's customers.

2.2.4 Customer Conservation and Electrification

General

Newfoundland Power and Hydro have jointly delivered CDM programs for customers since 2009. The utilities have developed a new plan to guide customer program delivery commencing in 2021.[30] The *Electrification, Conservation and Demand Management Plan: 2021-2025* continues longstanding customer CDM programs and introduces customer electrification programs.[31]

Customer CDM and electrification programs are complementary. As customers' energy usage increases through electrification, it becomes increasingly important to manage impacts on system

[28] Customers' satisfaction with the Company's service delivery averaged approximately 86% from 2011 to 2020.

[29] A loss of supply from Hydro and a series of electrical system events from January 2-8, 2014 caused widespread outages to Newfoundland Power's customers, known as #darkNL.

[30] Newfoundland Power filed an application with the Board on December 16, 2020 seeking approval of supplemental capital expenditures and an Electrification Cost Deferral Account to enable the delivery of electrification programs in 2021. See the *2021 Electrification, Conservation and Demand Management Application*.

[31] See *Volume 2, Supporting Materials, Tab 7, Electrification, Conservation and Demand Management Plan: 2021-2025*.

peak and related system costs through CDM. Both CDM and electrification programs result in lower overall costs for customers.[32]

Newfoundland Power will evaluate its electrification and CDM programs annually to ensure they continue to be cost-effective for customers.[33]

Customer Electrification Programs

The introduction of customer electrification programs is consistent with the Board's recommendations as part of the *Reference on Rate Mitigation Options and Impacts.*[34]

Electrification programs include incentives for residential and commercial customers to purchase an electric vehicle and associated charger. They also include a custom program that provides individualized incentives to help commercial customers replace a range of fossil-fuel technologies with equivalent electric technologies.[35]

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[32] For example, a customer who upgrades their insulation and thermostats through a CDM program would experience overall net savings of approximately $8,800 over the life of those technologies. Similarly, a customer who purchases an electric vehicle would experience overall net savings of approximately $5,200 through reduced maintenance and fuel costs over the life of that vehicle.

[33] The cost-effectiveness of CDM programs is evaluated using the Total Resource Cost ("TRC") test and the Program Administrator Cost ("PAC") test, as approved by the Board in Order No. P.U. 18 (2016). The cost-effectiveness of electrification programs is proposed to be evaluated using the modified Total Resource Cost ("mTRC") test, as outlined in Newfoundland Power's *2021 Electrification, Conservation and Demand Management Application,* filed with the Board on December 16, 2020.

[34] The Board recommended the utilities and Provincial Government work together on a comprehensive and coordinated approach to developing the most appropriate programs for the province. See the Board's *Rate Mitigation Options and Impacts, Muskrat Falls Project – Final Report*, February 7, 2020, page 109.

[35] Examples of individualized projects include: (i) the installation of ductless mini-split heat pumps for space heating; (ii) the electrification of business processes; (iii) dockside electrification; and (iv) the purchase of electric forklifts. For a description of each program, see *Volume 2, Supporting Materials, Tab 7, Electrification, Conservation and Demand Management Plan: 2021-2025, Schedule F.*

Electrification programs will provide a rate mitigating benefit for Newfoundland Power's customers over the long term.[36] For example, increased net revenue through electrification will provide a rate mitigating benefit for the Company's customers of approximately 0.5¢/kWh by 2034.[37] This equates to $100 in reduced electricity charges that year for an average residential customer with electric heating.[38]

Table 2-2 provides forecast annualized energy usage attributable to each customer electrification program from 2021F to 2025F.

Table 2-2:
Customer Electrification Programs
Annualized Energy Usage
2021F to 2025F
(GWh)

Program	2021F	2022F	2023F	2024F	2025F	Total
Residential Electric Vehicle and Charger	0.3	1.5	4.3	9.3	17.1	32.5
Commercial Electric Vehicle and Charger	0.1	0.4	1.0	2.4	4.8	8.7
Custom Electrification (Commercial)	0.1	0.5	1.0	1.7	2.6	5.9
Total	**0.5**	**2.4**	**6.3**	**13.4**	**24.5**	**47.1**

Electrification programs are forecast to result in cumulative energy usage of approximately 47.1 GWh by 2025.

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[36] The rate mitigating benefit of customer electrification programs was assessed through a Net Present Value ("NPV") analysis. The NPV analysis assessed the net revenue impact of increased energy sales through customer electrification to 2034. The net revenue impact was then divided by projected Company energy sales, including energy sales from electrification, to determine an indicative customer rate impact.

[37] The customer rate impact of 0.5¢/kWh was determined by dividing the net revenue impact of $33.9 million in 2034 by the projected Company energy sales, including energy sales from electrification, of 6,527 GWh.

[38] The average annual energy usage of an all-electric residential customer was 17,412 kWh in 2019 ((17,412 kWh x 0.5¢/kWh) * 1.15 HST = $100).

Electrification programs are forecast to increase peak demand by 3.2 MW by 2025. This increase in peak demand is forecast to be offset by peak demand savings from customer CDM programs.[39]

Table 2-3 provides the estimated cost of delivering customer electrification programs from 2021F to 2025F.

Table 2-3:
Customer Electrification Costs
2021F to 2025F
($000s)

Cost Category	**2021F**	**2022F**	**2023F**	**2024F**	**2025F**
General[40]	136	210	187	199	219
Program[41]	1,336	3,014	3,944	4,494	4,385
Total	**1,472**	**3,224**	**4,131**	**4,693**	**4,604**

Costs associated with delivering customer electrification programs are forecast to average approximately $3.6 million annually from 2021 to 2025.

Customer Conservation Programs

The continued delivery of CDM programs is necessary to meet customers' service expectations. Customers continue to express significant interest in CDM programs.

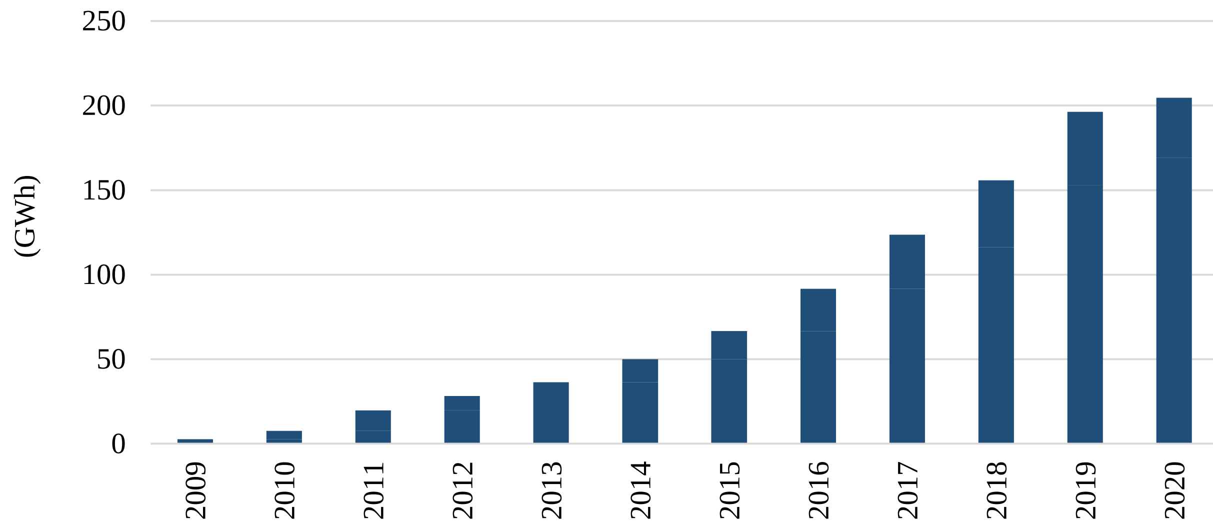
39 Customer CDM programs are forecast to achieve a peak demand reduction of approximately 70 MW over the same period.

40 General expenses include costs for planning, customer education and support (e.g. responding to customer enquiries).

41 Program costs include costs directly associated with customer program delivery (e.g. customer rebates), related research and customer support for electric vehicle infrastructure.

Figure 2-4 shows the annualized energy savings achieved by Newfoundland Power's customers through CDM programs from 2009 to 2020.[42]

Figure 2-4:
Customer Conservation Programs
Annualized Energy Savings
2009 to 2020



Cumulative energy savings totaled 973 GWh over the 2009 to 2020 period. Customers also achieved peak demand savings of 45 MW by 2020.

These energy and peak demand savings reduced costs to Newfoundland Power's customers from 2 perspectives. First, customers participating in CDM programs realized electricity bill savings of

[42] Energy savings from customer CDM programs are realized over many years. For example, insulation installed by a customer is expected to yield energy savings for 25 years. Insulation installed by a customer in 2020 will continue to provide energy savings each year until 2045. Annualized energy savings reflect the total savings realized each year over the lifetime of the technologies installed through each program.

approximately $118 million from 2009 to 2020. Second, all Newfoundland Power customers benefited from reduced system costs of approximately $135 million over this period.[43]

Planned changes to customer CDM programs over the 2021 to 2025 period include:

(i) Adjustment of the Business Efficiency Program in 2021 to support demand management opportunities for commercial facilities that convert space and water heating to electric.

(ii) Introduction of a low-income program in 2022 that will provide income-qualified customers with an energy efficiency kit at no cost to the participant.

(iii) Expansion of an on-bill rebate program in 2022 to include rebates for duct insulation and air sealing to help customers manage space heating costs.

(iv) Conclusion of the Instant Rebates Program after 2022.

Customers are forecast to achieve cumulative energy savings of approximately 1,279 GWh from 2021 to 2025. Customers are forecast to achieve peak demand savings of approximately 70 MW by 2025.

[43] System cost savings for the 2009 to 2020 period were updated based on a program evaluation conducted in March 2021. System cost savings through customer CDM programs result from avoided energy costs through customers' energy savings, as well as avoided capacity costs through reductions in peak demand. System cost savings are calculated as the net present value of avoided energy and capacity costs using marginal cost information provided by Hydro. Of the $135 million system cost savings, approximately 84%, or $114 million, resulted from avoided energy costs. Approximately 16%, or $21 million, resulted from avoided capacity costs.

Table 2-4 provides the estimated cost of delivering customer CDM programs from 2021F to 2025F.

Table 2-4:
Customer CDM Costs
2021F to 2025F
($000s)

	2021F	2022F	2023F	2024F	2025F
General[44]	646	676	759	842	824
Program[45]	6,530	7,170	7,006	6,305	6,560
Total	**7,176**	**7,846**	**7,765**	**7,147**	**7,384**

Costs related to customer CDM programs are forecast to average approximately $7.5 million annually from 2021 to 2025.

2.3 OPERATIONS AND RELIABILITY MANAGEMENT

2.3.1 System Overview

Newfoundland Power is the primary distributor of electricity in the province of Newfoundland and Labrador. The Company currently serves approximately 87% of all electricity customers in the province.

Newfoundland Power owns and operates approximately 10,750 kilometers of distribution line, 2,100 kilometers of transmission line, and 131 substations to serve customers throughout its service territory. These assets have been in operation for an average of approximately 30 years.

[44] General expenses include costs for customer education and support (e.g. responding to customer enquiries).
[45] Program delivery costs include costs directly associated with customer programs and related research.

The Company operates 23 hydroelectric plants that generate approximately 438 GWh annually. These plants have provided customers with low-cost electricity for over 100 years.[46] The Company also operates 4 combustion turbines and 2 diesel units. These generation assets are operated, when necessary, to serve customers experiencing localized outages and to provide system support when requested by Hydro.

Newfoundland Power's generation assets produce approximately 7% of the energy required to serve its customers. The remainder is purchased from Hydro. Hydro is the primary generator and transmitter of bulk electricity on the Island Interconnected System.

2.3.2 Electrical System Reliability

Reliability Performance

Newfoundland Power's electrical system is constructed to meet national standards.[47] These standards ensure the electrical system operates safely and reliably under conditions the Company could reasonably expect to occur throughout its service territory ("normal operating conditions").

Assessing the service reliability experienced by customers requires assessing both the duration and frequency of customer outages. Outage duration is measured using the System Average Interruption Duration Index ("SAIDI"). Outage frequency is measured using the System Average Interruption Frequency Index ("SAIFI").[48]

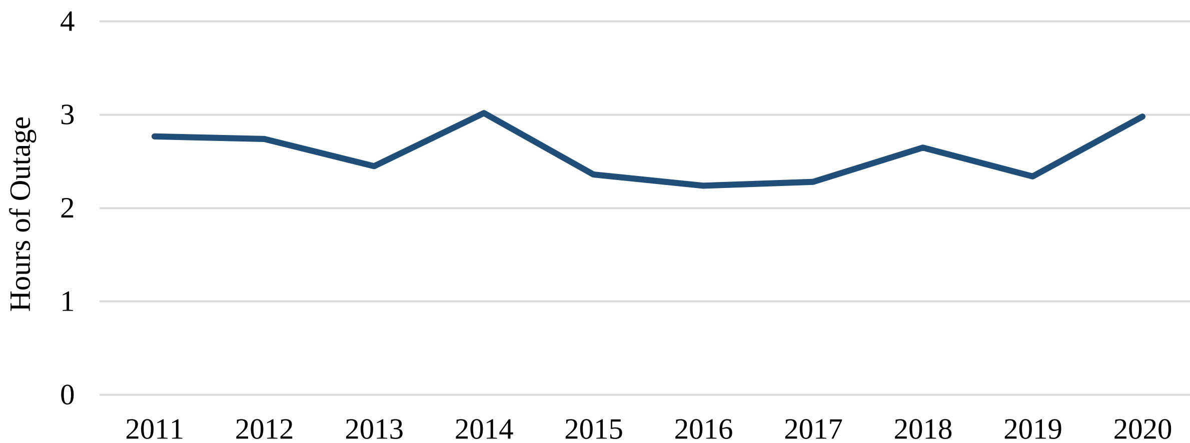
[46] The Company's Petty Harbour Hydroelectric Plant was commissioned in 1900. The Company's newest hydroelectric plant, located in Rose Blanche, was commissioned in 1998.

[47] The primary engineering standard is the Canadian Standards Association ("CSA") standard *C22.3 No.1-15, Overhead Systems*. This standard guides the construction of overhead distribution and transmission systems.

[48] Newfoundland Power calculates its reliability performance according to Canadian Electricity Association ("CEA") guidelines. The CEA's recommended reporting standard is IEEE Std 1366 – 2012, contained within the *IEEE Guide for Electric Power Distribution Reliability Indices*. All reliability data calculated by the Company follows this reporting standard.

Figure 2-5 shows the average duration of outages experienced by Newfoundland Power's customers from 2011 to 2020 under normal operating conditions.

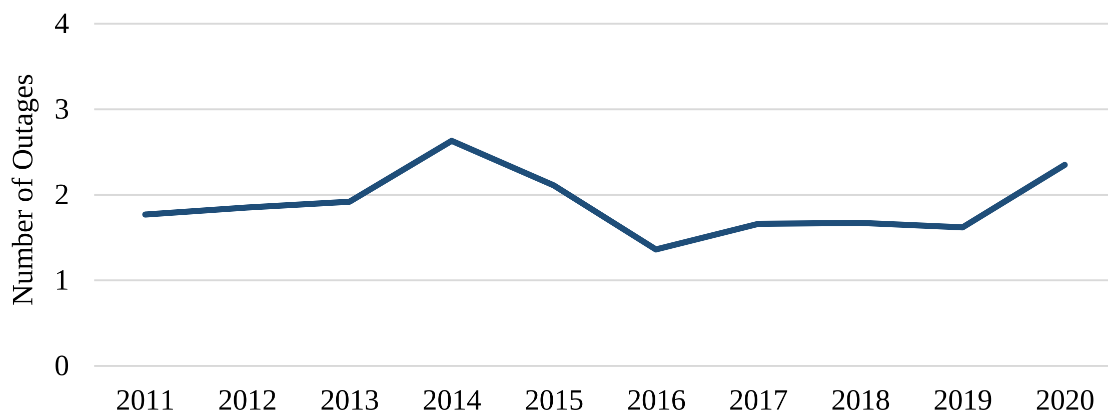
Figure 2-5:
SAIDI
Newfoundland Power
Normal Operating Conditions
2011 to 2020



The duration of customer outages has been reasonably consistent under normal operating conditions since 2011. Customers have experienced an average of approximately 2 to 3 hours of outage per year over this period.

Figure 2-6 shows the average number of outages experienced by the Company's customers from 2011 to 2020 under normal operating conditions.

Figure 2-6:
SAIFI
Newfoundland Power
Normal Operating Conditions
2011 to 2020

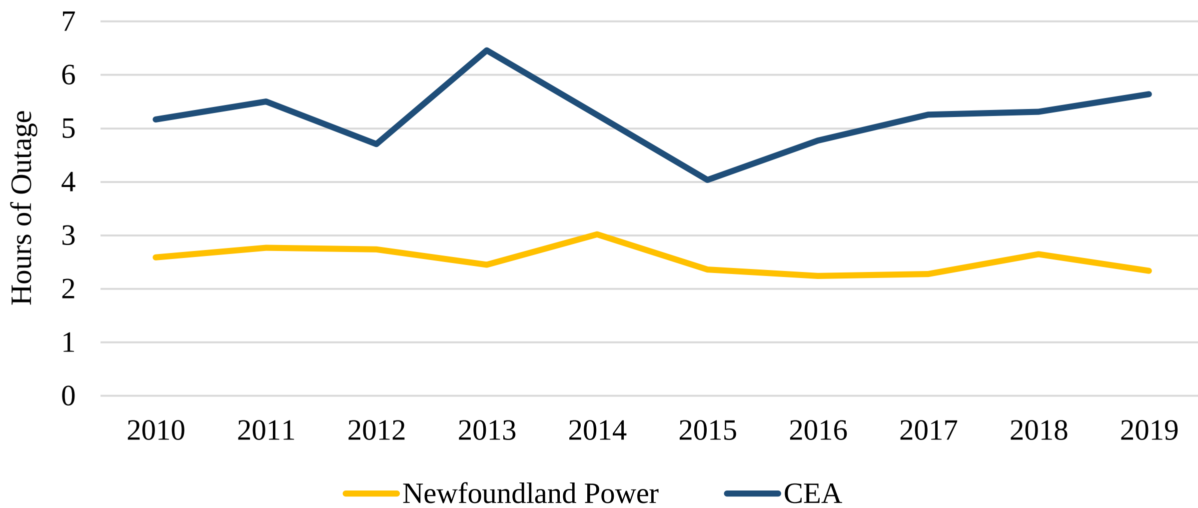


Under normal operating conditions, customers have experienced an average of 1 to 3 outages per year since 2011.

Comparing Newfoundland Power's system reliability to the Canadian average is a reasonable means through which to assess the Company's performance.

Figure 2-7 shows the average duration of outages experienced by Newfoundland Power's customers in comparison to the Canadian average from 2010 to 2019.[49]

Figure 2-7:
SAIDI
Newfoundland Power vs. Canadian Average
Normal Operating Conditions
2010 to 2019



Since 2010, the average duration of outages experienced by Newfoundland Power's customers has been approximately ½ the Canadian average under normal operating conditions.[50]

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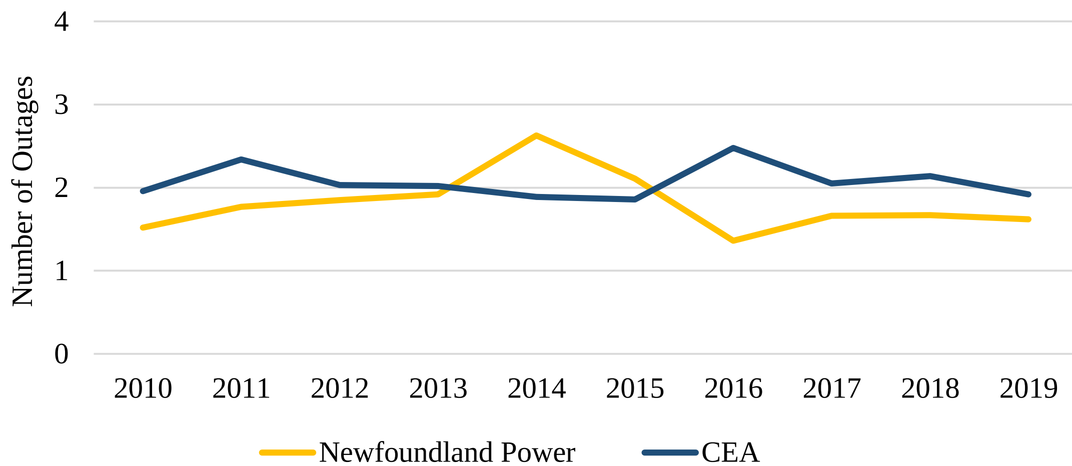
[49] References to the Canadian average in *Section 2: Customer Operations* refer to Region 2 utilities that are members of the CEA. Region 2 utilities include Canadian utilities that serve a mix of urban and rural markets. These are ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro Quebec, Manitoba Hydro, Maritime Electric, NB 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. CEA reliability data for 2020 was not available at the time of preparing this Application.

[50] Newfoundland Power's SAIDI averaged approximately 2.5 hours under normal operating conditions from 2010 to 2019, compared to a CEA average of 5.2 hours (2.5 / 5.2 = 0.48).

Figure 2-8 shows the average frequency of outages experienced by Newfoundland Power's customers in comparison to the Canadian average from 2010 to 2019.

Figure 2-8:
SAIFI
Newfoundland Power vs. Canadian Average
Normal Operating Conditions
2010 to 2019



Since 2010, the average number of outages experienced by Newfoundland Power's customers has been broadly consistent with the Canadian average under normal operating conditions.

Newfoundland Power's electrical system is not constructed or expected to fully withstand the impact of extreme weather conditions, such as severe wind and ice storms. These events generally exceed the design parameters of the electrical system and may cause extensive damage.[51] Utility reporting standards consider these conditions to be "significant events."[52]

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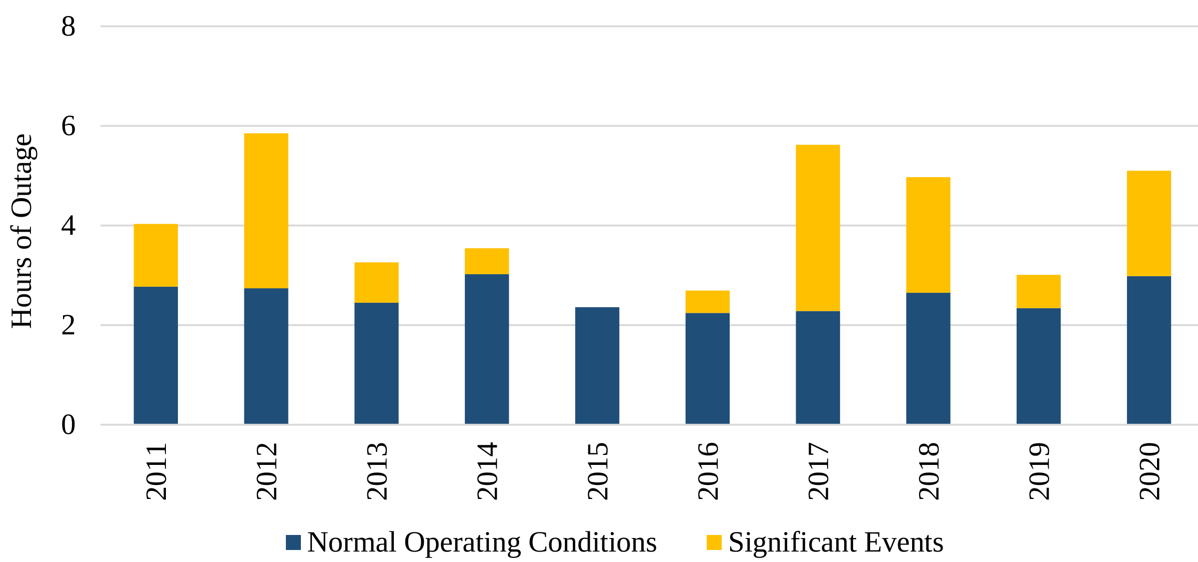
[51] Significant events generally affect the duration of outages more than the frequency of outages. For example, a hurricane may result in a single outage that lasts several days.

[52] The CEA defines significant events as *"events that exceed reasonable design and/or operational limits of the electrical power system."*

Figure 2-9 shows the average duration of outages experienced by Newfoundland Power's customers including significant events from 2011 to 2020.[53]

Figure 2-9:
Newfoundland Power SAIDI
Including Significant Events
2011 to 2020



Significant events have become more frequent in Newfoundland Power's service territory. Over the last decade, significant events caused outages to Newfoundland Power's customers in 9 of 10 years. This compares to 2 significant events over the prior decade.[54]

These events can have a material impact on the service reliability experienced by customers. For example, a severe windstorm with gusts of nearly 180 km/hour occurred in March 2017. This

[53] Figure 2-9 does not include outages caused by a loss of supply from Hydro.
[54] From 2001 to 2010, significant events resulted in customer outages in 2007 and 2010.

event increased the average duration of customer outages in 2017 from 2.3 hours under normal operating conditions, to 5.6 hours.[55]

Reliability Management

Newfoundland Power's operations are focused on maintaining current levels of service reliability for customers.[56]

Service reliability principally reflects the general condition of the electrical system and Newfoundland Power's response when outages occur.

The Company completes routine inspections of its electrical system to proactively identify deteriorated equipment and necessary repairs or replacements. Substations are inspected 8 times annually, transmission lines are inspected annually, and distribution lines are inspected on a 7-year cycle. Equipment repairs or replacements are prioritized based on a combination of factors, including risk of failure, identified safety issues, and the likelihood of customer outages.

Over ½ of the Company's annual capital investments are focused on the replacement of deteriorated assets and the refurbishment of assets to extend their useful service life.

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[55] The March 2017 windstorm resulted in approximately 47 million customer minutes of outage. Significant events in 2017 also included a snow storm that resulted in approximately 5 million customer minutes of outage.

[56] In Newfoundland Power's *2010 General Rate Application*, the Company stated it considered then current levels of service reliability to be satisfactory (see Volume 1 (1st Revision), Section 2: Customer Operations, Page 2-8, Line 6). Similarly, the Company has characterized its electrical system performance as reliable in its *2013/2014 General Rate Application* (see Volume 1, Section 1: Introduction, Page 1-3, Line 10), its *2016/2017 General Rate Application* (see Volume 1 (1st Revision), Section 1: Introduction, Page 1-3, Line 11), and its *2019/2020 General Rate Application* (see Volume 1, Section 1: Introduction, Page 1-3, Line 21).

The refurbishment and replacement of assets is principally based on asset condition and risks to customers in the event of a failure. For example, the Company's *Transmission Line Rebuild Strategy* focuses on rebuilding sections of transmission lines that have been in operation since the 1960s. Projects are prioritized based on deterioration observed in the field and the criticality of a transmission line in serving customers.[57]

Asset condition and customer impact are also considered in Newfoundland Power's annual *Distribution Reliability Initiative*. This initiative identifies the Company's worst-performing distribution feeders and whether capital investment would improve the reliability experienced by customers served by those feeders.[58]

Newfoundland Power's inspection and maintenance practices and capital investments have contributed to a 39% reduction in the number of equipment failures experienced over the last 2 decades.[59]

The most recent independent review of Newfoundland Power's operations was conducted in 2014. The review found that the Company uses an effective combination of periodic inspections, maintenance and capital investments.[60]

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57 See Newfoundland Power's *2022 Capital Budget Application, Report 3.1 2022 Transmission Line Rebuild.*

58 See Newfoundland Power's *2022 Capital Budget Application, Report 4.1 Distribution Reliability Initiative.*

59 From 2011 to 2020, Newfoundland Power experienced an average of 1,011 equipment failures annually, compared to an average of 1,658 equipment failures annually from 2001 to 2010 ((1,011 - 1,658) / 1,658 = -0.39, or -39%).

60 See Liberty Consulting Group, *Report on Island Interconnected System to Interconnection with Muskrat Falls Addressing Newfoundland Power*, page ES-2.

2.3.3 Field Response

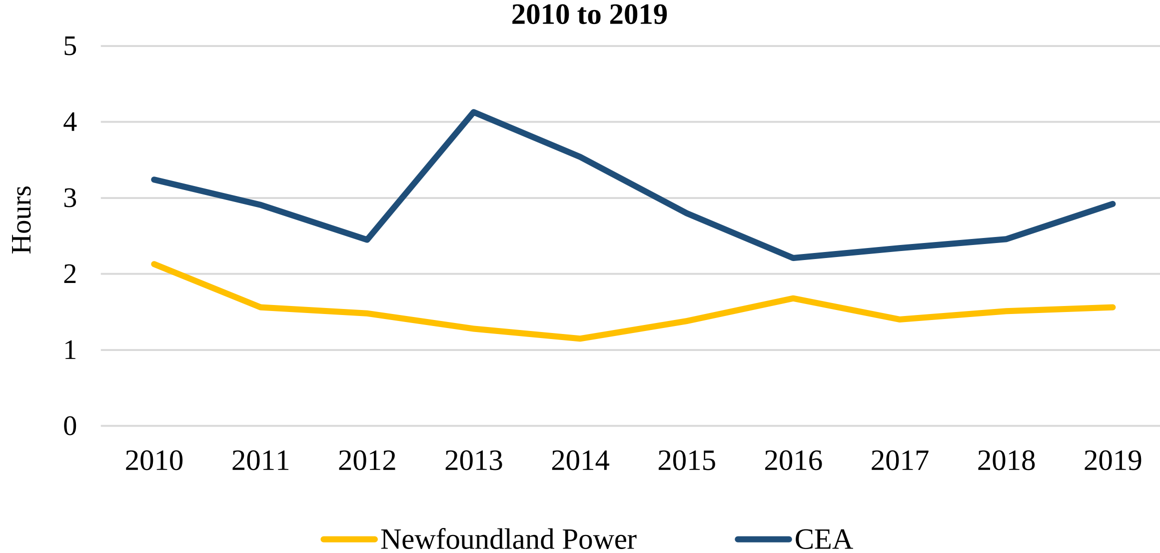
Field Response Performance

As the primary distributor of electricity in the province of Newfoundland and Labrador, Newfoundland Power must be responsive to customer outages and customer-driven work requests.

Newfoundland Power compares its responsiveness to other utilities using the Customer Average Interruption Duration Index ("CAIDI"). CAIDI measures the average time it takes to restore service to customers following an unscheduled outage.[61]

Figure 2-10 compares Newfoundland Power's average restoration time for unscheduled outages to the Canadian average from 2010 to 2019.[62]

Figure 2-10:
CAIDI
Newfoundland Power vs. Canadian Average
2010 to 2019



[61] CAIDI is the restoration time measure used by the CEA. In arithmetic terms, CAIDI is SAIDI / SAIFI.
[62] Figure 2-10 excludes significant events.

Newfoundland Power's average restoration time for unscheduled outages has been approximately ½ the Canadian average since 2010.[63]

The Company maintains operational performance targets to ensure a timely response to customer-driven work requests. Newfoundland Power aims to complete new service connections within 10 business days. The Company's target is to meet this timeframe for at least 85% of new service connections.

Newfoundland Power has met its target for completing new service connections in each of the last 5 years. The Company's average response time for completing new service connections was approximately 7.7 days from 2016 to 2020.

Customers have indicated a reasonable level of satisfaction with Newfoundland Power's field response. Over the last 5 years, customers who required assistance in the field indicated an average satisfaction level of 93%.

Field Response Capabilities

Newfoundland Power's service territory is vast at approximately 70,000 km^2. It is almost 1,000 kilometers from Trepassey on the Avalon Peninsula, to Port aux Basques on the southwest coast. It is over 300 kilometers from Fortune on the Burin Peninsula to Bonavista.

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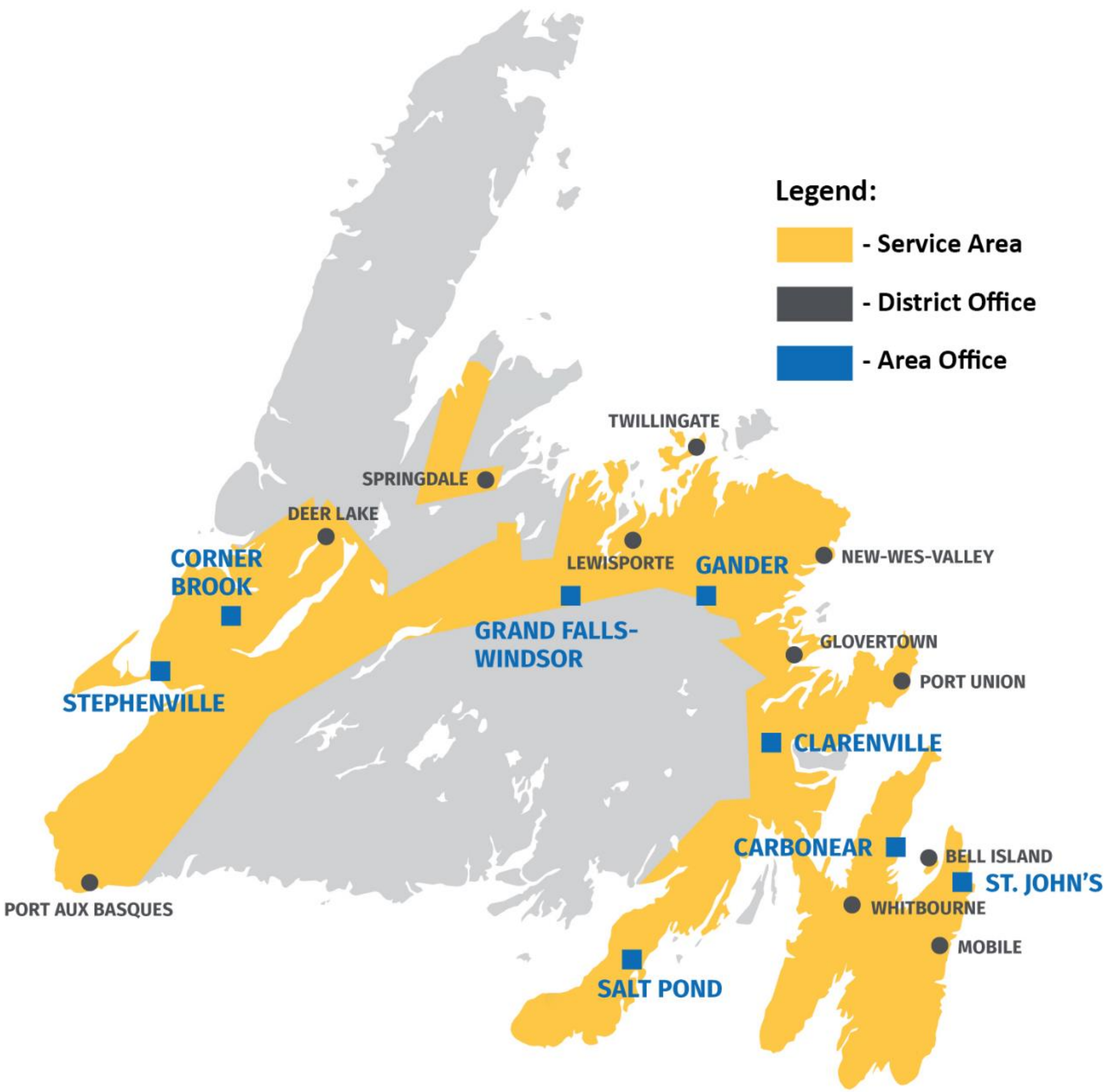
63 From 2010 to 2019, Newfoundland Power's average restoration time was 1.5 hours compared to a CEA average of 2.9 hours (1.5 / 2.9 = 0.52).

Newfoundland Power responds to customer outages and customer-driven work requests using a combination of workforce management, operational technologies, and electrical system automation.

Figure 2-11 shows the Company's service territory, including the location of Company offices.

Figure 2-11:
Newfoundland Power's Service Territory



Newfoundland Power maintains a skilled workforce throughout its service territory to ensure a timely response to customer outages and customer-driven work requests. For example, in 2020 the Company employed approximately 140 powerline technicians, 105 engineers and engineering technologists, and 85 employees with skilled trades.

Newfoundland Power deploys its workforce using a combination of operational technologies. A technology-based, centralized dispatching process was implemented in 2014.[64] A modern SCADA system and Geographic Information System were implemented in 2016.[65] Together, these systems provide information on the status of the electrical system, where to dispatch crews when issues arise, and the progress of ongoing field work.

Newfoundland Power implemented a new Outage Management System in 2019.[66] The Outage Management System automatically assesses outage reports from customers and groups related outages, such as multiple reports from customers on a single distribution feeder. For example, following a severe blizzard in January 2020, the Outage Management System assessed and grouped approximately 5,000 reports related to approximately 1,300 customer outages.

The automatic assessment of outages provides multiple customer benefits. It reduces the amount of time required to assess outages, thereby enabling a prompt response to customers. It also provides a more accurate assessment of outage location, which supports the efficient dispatching

[64] Centralized dispatching technologies include a Workforce Management System, Automatic Vehicle Location System, and mobile technology in line trucks. A centralized team uses these technologies to coordinate and monitor the day-to-day completion of field work throughout the Company's service territory.

[65] "SCADA system" denotes Supervisory Control and Data Acquisition System. Together, the SCADA system and Geographic Information System provide a geographic view of customer outages and where field crews must be dispatched to restore service.

[66] Implementation of the Outage Management System was approved in Order No. P.U. 37 (2017).

of crews in the field. Additionally, timely and accurate outage information allows the Company to provide better information to customers on the status of outages.[67]

Newfoundland Power's field response capabilities are supported by automation throughout the distribution system. The Company automated 100% of its distribution feeders at year-end 2019.[68] This automation provides real-time information on the status of the electrical system and allows distribution feeders to be operated remotely without dispatching field crews.[69]

Newfoundland Power has also automated its distribution system through the installation of downline reclosers. Downline reclosers are pole-mounted devices that essentially divide a distribution feeder into multiple sections. These devices are controlled remotely to: (i) isolate a fault so only a portion of customers on a feeder experience an outage, instead of all customers; and (ii) systematically restore power to customers following a prolonged outage.

The number of downline reclosers installed throughout Newfoundland Power's distribution system nearly doubled from 52 in 2017 to 92 in 2020.[70]

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[67] For example, Newfoundland Power provides an Outage Alert service to its customers. Historically, all customers subscribing to this service would receive an Outage Alert if any section of their distribution feeder was experiencing an outage. With the new Outage Management System, only customers whose services are directly affected by an outage receive an Outage Alert. Approximately 13,000 customers subscribed to Outage Alerts at year-end 2020. This is approximately 55% greater than the number of customers subscribed to Outage Alerts at year-end 2015.

[68] Newfoundland Power commenced the large-scale automation of its distribution system following the implementation of a more modern SCADA system in 1999. There are currently 3 small feeders serving less than 10 customers that are not included in the assessment. Newfoundland Power does not intend to automate these feeders.

[69] Automated distribution feeders also provide real-time visibility on the voltage and customer load on a feeder, which is used to manage peak load on the system and restore service to customers after a prolonged outage.

[70] Newfoundland Power's *2020 Capital Budget Application* outlined the Company's approach to installing downline reclosers. See *Report 4.5 Distribution Feeder Automation*.

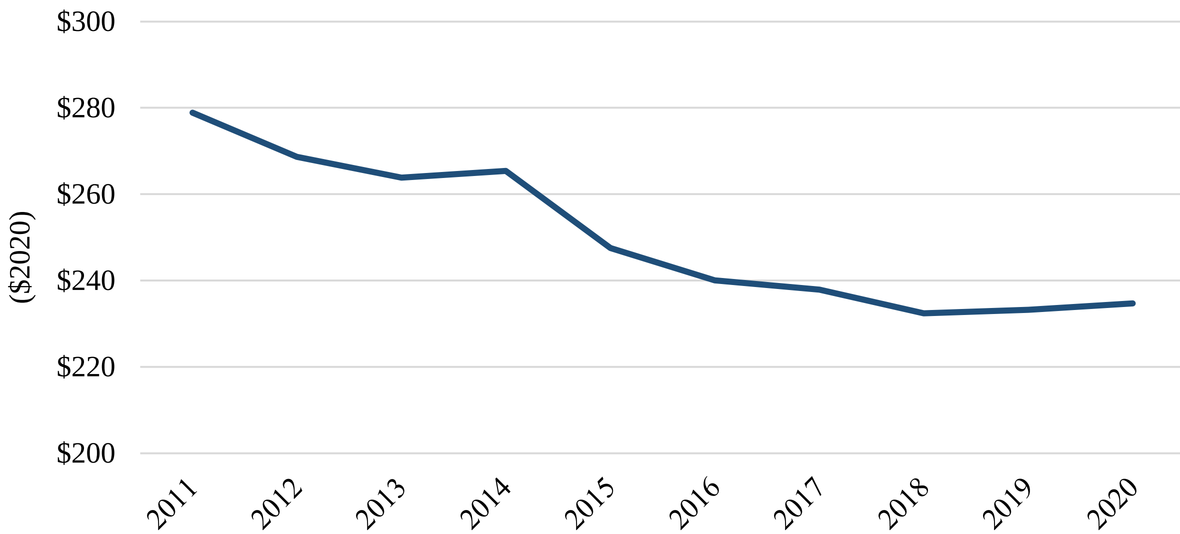
This automation provides greater flexibility in managing the Company's field crews, particularly during significant events. For example, the operation of 5 downline reclosers during a severe blizzard in January 2020 avoided approximately 3.5 million customer outage minutes without the assistance of field crews.

2.3.4 Operating Efficiency

Newfoundland Power provides service to its customers in an efficient manner.[71] The Company's overall operating efficiency can be observed in its operating cost per customer.

Figure 2-12 shows Newfoundland Power's operating cost per customer from 2011 to 2020 on an inflation-adjusted basis.[72]

Figure 2-12:
Operating Cost per Customer
2011-2020



[71] Efficient utility operations is consistent with the provincial power policy. Specifically, section 3(b)(i) of the *Electrical Power Control Act, 1994* requires that all sources and facilities for the production, transmission and distribution of power in the province be managed and operated in a manner that results in the most efficient production, transmission and distribution of power.

[72] Non-labour costs are inflation-adjusted using the GDP Deflator for Canada. Labour costs are inflation-adjusted using Newfoundland Power's labour inflation rate.

From 2011 to 2020, Newfoundland Power reduced its operating cost per customer by approximately 16% when adjusted for inflation.[73]

The effective use of technology has been a primary means through which the Company has improved its operating efficiency over the last decade. This includes the implementation of technologies that enable efficient customer service delivery, such as AMR meters and the HVCA system.[74] It also includes technologies that enable an efficient response to customer outages and customer-driven work requests, such as operational technologies and electrical system automation.[75]

2.4 OPERATING AND CAPITAL COSTS

2.4.1 Operating Costs

General

Gross operating costs represent approximately 9.6% of Newfoundland Power's proposed 2023 revenue requirement from customer rates.[76]

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[73] Operating costs were approximately $235/customer in 2020 and $279/customer in 2011 when adjusted for inflation ((235 - 279) / 279 = -0.16, or -16%). Higher operating costs in 2014 were attributed to: (i) higher labour costs associated with restoration and customer service efforts following widespread customer outages in January 2014 known as #darkNL; (ii) increased distribution maintenance costs, largely due to weather conditions; and (iii) an increase in bad debt expense associated with higher customer account balances during the winter of 2014.

[74] For more information, see *Section 2.2.2 Customer Service Efficiency*.

[75] For more information, see *Section 2.3.3 Field Response*.

[76] See *Volume 1, Application, Company Evidence and Exhibits*, *Exhibit 1 and Exhibit 7,* page 2 ($68,599,000 / $712,803,000 = 0.096, or 9.6%).

Table 2-5 provides Newfoundland Power's gross operating costs from 2019 to 2023F.

Table 2-5:
Gross Operating Costs
2019 to 2023F
($000s)

2019	2020	2021F	2022F	2023F
61,726	63,444	64,309	66,508	68,599

Gross operating costs are forecast to increase by approximately 11%, or $6.9 million, from 2019 to 2023. This represents an annual increase in operating costs of approximately 2.8%, or $1.7 million per year.

An examination of Newfoundland Power's gross operating costs by function and breakdown provides a greater understanding of these costs. Classification by function focuses on the underlying reason for incurring a cost. Classification by breakdown focuses on the nature of a cost. For example, the Company classifies the salary of a Customer Service Representative in 2 ways: (i) by function as a customer service cost; and (ii) by breakdown as a labour cost.

Exhibits 1 and 2 of *Volume 1, Application, Company Evidence and Exhibits* show the Company's gross operating costs by function and breakdown, respectively.

Operating Costs by Function

Table 2-6 summarizes Newfoundland Power's operating costs by 3 functional categories from 2019 to 2023F: (i) electricity supply; (ii) customer services; and (iii) general.

Table 2-6:
Operating Costs by Function
2019 to 2023F
($000s)

Function	**2019**	**2020**	**2021F**	**2022F**	**2023F**
Electricity Supply	28,473	29,144	27,972	28,705	29,422
Customer Services	10,434	10,437	10,792	11,096	11,257
General	22,819	23,863	25,545	26,707	27,920
Total	**61,726**	**63,444**	**64,309**	**66,508**	**68,599**

Table 2-7 shows operating costs associated with the electricity supply category by function from 2019 to 2023F.

Table 2-7:
Operating Costs – Electricity Supply
2019 to 2023F
($000s)

Function	**2019**	**2020**	**2021F**	**2022F**	**2023F**
Distribution	10,236	10,945	9,227	9,487	9,741
Transmission	712	919	957	978	999
Substations	2,361	2,258	2,356	2,422	2,487
Power Produced	3,940	3,797	3,930	4,027	4,122
Administration and Engineering	7,972	7,934	8,204	8,433	8,657
Telecommunications	1,286	1,299	1,350	1,374	1,397
Environment	287	273	282	289	296
Fleet Operations and Maintenance	1,679	1,719	1,666	1,695	1,723
Total	**28,473**	**29,144**	**27,972**	**28,705**	**29,422**

Electricity supply costs for 2023 are forecast to increase by approximately 3.3%, or $949,000, compared to 2019. This represents an annual increase in electricity supply costs of approximately 0.8%, or $237,000 per year.

The increase in electricity supply costs reflects a combination of reduced distribution costs and higher administration and engineering costs. Reduced distribution costs primarily reflect reduced maintenance requirements for street lights due to implementation of the *LED Street Lighting Replacement Plan*.[77] Higher administration and engineering costs primarily reflect labour inflation.[78]

Table 2-8 provides costs associated with the customer services category by function from 2019 to 2023F.

Table 2-8:
Operating Costs – Customer Services
2019 to 2023F
($000s)

Function	**2019**	**2020**	**2021F**	**2022F**	**2023F**
Customer Service	7,726	7,468	7,875	8,038	8,103
Conservation	728	679	782	886	946
Uncollectible Bills	1,980	2,290	2,135	2,172	2,208
Total	**10,434**	**10,437**	**10,792**	**11,096**	**11,257**

77 Lower street light maintenance requirements are forecast to reduce operating costs by approximately $1.9 million starting in 2021.

78 Regular and temporary labour costs under the administration and engineering function are forecast to increase by approximately $583,000 from 2019 to 2023, or approximately 2.8% per year.

Customer services operating costs for 2023 are forecast to increase by approximately 7.9%, or $823,000, compared to 2019. This represents an annual increase in customer services costs of approximately 2%, or $206,000 per year.

Increased customer services costs reflect: (i) labour inflation, which is partially offset by operating efficiencies gained through replacement of the existing Customer Service System;[79] (ii) increased conservation and electrification costs due to implementation of the new *Electrification, Conservation and Demand Management Plan: 2021-2025;* and (iii) increased uncollectible bills expense.

Table 2-9 provides costs associated with the general category by function from 2019 to 2023F.

Table 2-9:
Operating Costs – General
2019 to 2023F
($000s)

	2019	**2020**	**2021F**	**2022F**	**2023F**
Information Systems	5,402	5,855	6,051	6,407	7,311
Financial Services	1,787	1,806	1,886	1,942	1,997
Corporate and Employee Services	14,233	14,504	15,529	16,052	16,267
Insurances	1,397	1,698	2,079	2,306	2,345
Total	**22,819**	**23,863**	**25,545**	**26,707**	**27,920**

[79] Regular and temporary labour costs under the customer service function are forecast to increase by approximately $483,000 from 2019 to 2023. This reflects labour inflation over the period, offset by operating efficiencies of approximately $91,000 in 2023 due to the implementation of a new Customer Information System, as approved by the Board in Order No. P.U. 12 (2021).

General operating costs are forecast to increase by approximately 22.4%, or $5.1 million, from 2019 to 2023. This represents an annual increase in general costs of approximately 5.6%, or $1,275,000 per year.

Increased general operating costs include higher information systems costs, corporate and employee services costs and insurance costs. Higher information systems costs primarily reflect an increase of approximately $1.6 million in licensing and support costs for third-party hardware and software solutions, including cybersecurity costs.[80] Higher corporate and employee services costs reflect inflationary increases and additional regulatory costs.[81] Higher insurance costs reflect an increase in Newfoundland Power's insurance premiums, which reflects general market trends.

Operating Costs by Breakdown

The primary breakdown categories of Newfoundland Power's operating costs are labour costs and other costs (i.e. non-labour costs).

[80] This includes increased costs of approximately: (i) $208,000 for infrastructure and network management; (ii) $268,000 for cybersecurity management; (iii) $439,000 for customer service software, such as the replacement Customer Information System; (iv) $183,000 for business back office software, such as the Human Resources Management System; and (v) $517,000 for operations and engineering software, such as the Outage Management System.

[81] Inflationary increases for corporate and employee services are approximately $1.3 million over the 2019 to 2023 period. Additional regulatory costs include, as examples, the addition of a director position to oversee the Company's Regulatory Affairs function, an analyst position in the department and increased other company fees.

Table 2-10 provides the breakdown of operating costs from 2019 to 2023F.

Table 2-10:
Operating Costs by Breakdown
2019 to 2023F
($000s)

	2019	**2020**	**2021F**	**2022F**	**2023F**
Labour	35,241	36,533	35,897	37,027	38,136
Other	26,485	26,911	28,412	29,481	30,463
Total	**61,726**	**63,444**	**64,309**	**66,508**	**68,599**

Labour costs are forecast to comprise approximately 56% of the Company's operating costs in 2023. Operating labour costs are an indicator of efficiency in Newfoundland Power's day-to-day operations.

Table 2-11 provides a breakdown of labour costs from 2019 to 2023F.

Table 2-11:
Labour Costs by Breakdown
2019 to 2023F
($000s)

	2019	**2020**	**2021F**	**2022F**	**2023F**
Regular and Standby	30,068	31,483	30,703	31,677	32,634
Temporary	2,151	1,625	1,990	2,050	2,108
Overtime	3,022	3,425	3,204	3,300	3,394
Total	**35,241**	**36,533**	**35,897**	**37,027**	**38,136**

Regular and standby labour costs are forecast to increase by approximately 8.5%, or $2.6 million, from 2019 to 2023. This represents an annual increase of approximately 2.1%, or $642,000, through the period.

The increase in regular and standby labour primarily reflects a combination of labour inflation and decreased labour costs associated with reduced street light maintenance.[82]

Temporary labour costs are forecast to decrease by 2.0%, or approximately $43,000, from 2019 to 2023. Temporary labour costs reflect an average of the amount of temporary labour required over the last 3 years, adjusted for labour inflation.

Overtime labour costs are forecast to increase by 12.3%, or approximately $372,000, from 2019 to 2023. Overtime labour costs reflect an average of the amount of overtime labour required over the last 3 years, adjusted for labour inflation.

Newfoundland Power is forecasting an annual increase in labour costs of approximately 2.1% from 2019 to 2023. The Company's weighted labour rate inflation is forecast to be approximately 3.1% per year over this period.[83] This implies an operating efficiency of approximately 1.0% per year.

Other costs are forecast to comprise approximately 44% of the Company's operating costs in 2023. Other costs include the goods and services the Company acquires from third parties to provide service to customers. These goods and services are typically acquired through

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[82] This includes labour inflation of approximately $3.6 million and reduced labour costs for street light maintenance of approximately $1.4 million.

[83] Weighted labour rate increases reflect a combination of collectively bargained base wage increases 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 progression through the apprenticeship program. The weighted labour rate increases are 2.92% in 2020, 2.75% in 2021, 3.00% in 2022, and 2.85% in 2023. The 3.00% forecast increase in 2022 includes a negotiated base wage increase of 2.25% and a 0.75% forecast progression. The 2.85% forecast increase in 2023 includes a 2.10% estimated base wage increase and a 0.75% forecast progression. On a compounded basis, the Company's weighted labour rate inflation is approximately 3.1% annually from 2019 to 2023.

competitive processes to ensure they are consistent with least-cost service delivery. Year-over-year variations in other costs generally reflect changes in Newfoundland Power's operating requirements, such as changes in requirements for computing equipment and software.

Other costs are forecast to increase by approximately 15%, or $4 million, from 2019 to 2023. This represents an annual increase of approximately 3.8%, or $995,000, through the period.

Increased other costs primarily reflect higher insurance costs, higher computing equipment and software costs, and inflationary increases.[84]

2.4.2 Capital Costs

Newfoundland Power's annual capital budget reflects expenditures necessary to maintain a large number of assets over a vast geographic area. The Company targets stability and predictability in its annual capital budgeting. This approach to capital budgeting is conducive to rate stability for customers.

[84] From 2019 to 2023, insurance costs are forecast to increase by approximately $948,000 and computing equipment and software costs are forecast to increase by approximately $1.6 million.

Table 2-12 provides capital expenditures by asset class from 2019 to 2023.[85]

Table 2-12:
Capital Expenditures by Asset Class
2019 to 2023F
($000s)

	2019[86]	2020[87]	2021F[88]	2022F	2023F
Distribution	46,801	44,897	45,767	47,744	51,456
Substations	17,133	14,732	14,280	11,639	17,581
Transmission	11,940	9,948	9,751	12,892	12,486
Generation	11,932	7,095	11,510	2,769	11,527
General Property	3,561	2,473	2,776	2,660	4,816
Transportation	4,223	3,869	4,032	3,089	4,239
Telecommunications	312	112	462	564	1,266
Information Systems	7,615	7,282	15,362	21,044	11,700
Total	**103,517**	**$90,408**	**103,940**	**102,401**	**115,071**

Capital expenditures are forecast to average approximately $107 million annually from 2021 to 2023. This compares to an average of approximately $97 million per year in 2019 and 2020.

Increased capital expenditures over the forecast period are primarily observed in the Distribution and Information Systems asset classes. Capital expenditures are reasonably stable across the other asset classes.

[85] These expenditures do not include the allowance for unforeseen, general expenses capitalized, or the proposals contained in the Application regarding the capitalization of pension expense by way of a labour loader. Capital expenditures for 2019 and 2020 include expenditures related to approved projects that were completed in subsequent years. Forecast capital expenditures for 2022 and 2023 reflect the Company's *2022 Capital Plan* included with Newfoundland Power's *2022 Capital Budget Application.*

[86] The Company's *2019 Capital Budget Application* was approved in Order No. P.U. 35 (2018).

[87] The Company's *2020 Capital Budget Application* was approved in Order No. P.U. 5 (2020).

[88] The Company's *2021 Capital Budget Application* was approved in Order Nos. P.U. 37 (2020), P.U. 10 (2021), and P.U. 12 (2021). See the *2021 Capital Expenditure Status Report* included with Newfoundland Power's *2022 Capital Budget Application.* Capital expenditures forecast for 2021 also include the Company's application for supplemental capital expenditures of $1,538,000 for an Electric Vehicle Charging Network filed with the Board on December 16, 2020.

Distribution capital expenditures are forecast to average approximately $48.3 million annually from 2021 to 2023, compared to an average of approximately $45.8 million annually in 2019 and 2020. Forecast Distribution capital expenditures include execution of the Company's multi-year *LED Street Lighting Replacement Plan* commencing in 2021.[89]

Information Systems capital expenditures are forecast to average approximately $16.0 million from 2021 to 2023, compared to an average of approximately $7.4 million annually in 2019 and 2020. Forecast Information Systems capital expenditures include replacement of Newfoundland Power's Customer Service System commencing in 2021.[90]

Newfoundland Power's annual capital program continues to focus on the refurbishment of assets to extend their useful service lives and the replacement of assets that can no longer provide safe and reliable service to customers. Over ½ of the Company's forecast capital expenditures relate to the replacement or refurbishment of existing assets.

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[89] Capital expenditures related to the *LED Street Lighting Replacement Plan* are forecast to average approximately $5.4 million annually from 2021 to 2023.

[90] Capital expenditures related to replacement of the Company's Customer Service System are forecast to be approximately $9.9 million in 2021, $15.8 million in 2022, and $5.9 million in 2023.

SECTION 3: FINANCE

3.1 OVERVIEW

The maintenance of Newfoundland Power's financial integrity is necessary to enable the delivery of safe and reliable electrical service to customers over the long term. Diligent financial management benefits both the Company and its customers.

Newfoundland Power's financial management has enabled the Company to maintain its financial integrity over time. The proposals in this Application are consistent with maintaining the financial integrity of the Company in 2022 and 2023 and are consistent with the fair return standard.

Expert evidence filed with this Application indicates a fair return for Newfoundland Power for 2022 and 2023 comprises: (i) a capital structure consisting of 45% common equity; and (ii) a return on equity of 9.8%. A 45% common equity component and a 9.8% rate of return on equity is consistent with maintaining Newfoundland Power's financial integrity and the fair return standard.

The Application proposes continued suspension of the Automatic Adjustment Formula for determining the Company's rate of return on equity between test years.

The Application proposes to increase the amortization period for CDM program costs from 7 years to 10 years, and the amortization of electrification program costs over 10 years. The amortization of program costs over 10 years is consistent with sound public utility practice.

The Board directed that Newfoundland Power review its methodology and calculation of General Expenses Capitalized. The Application proposes minor changes to the Company's calculation of General Expenses Capitalized and the capitalization of pension costs by way of a labour loader.

The Company is proposing to amortize up to $1 million in Board and Consumer Advocate costs in relation to this Application over a 34-month period. Cost differences from $1 million are proposed to be recovered or rebated through the Company's Rate Stabilization Account. The Company also proposes to amortize a 2022 revenue shortfall of approximately $1.3 million over a 34-month period.

3.2 FINANCIAL PERFORMANCE: 2019 TO 2023

Newfoundland Power manages its financial performance over the long and short term to ensure its continued financial integrity. The Company's financial integrity up to 2021 is reflective of this stable and consistent approach to financial management. Excluding the proposals in this Application, Newfoundland Power's financial integrity deteriorates over the 2022 to 2023 period.

Exhibit 3 in Volume 1, Application, Company Evidence and Exhibits details Newfoundland Power's actual financial performance for 2019 and 2020. Exhibit 3 also shows forecast financial performance for 2021 to 2023, excluding the proposals in this Application.

Exhibit 5 in Volume 1, Application, Company Evidence and Exhibits compares forecast financial performance for 2022 and 2023 based on existing customer rates and proposed rates, which incorporate the proposals in this Application.

3.2.1 Revenue

Energy Sales and Electricity Revenue

Table 3-1 shows energy sales and electricity revenue from 2019 to 2023E, excluding the proposals in this Application.[1]

Table 3-1:
Energy Sales and Electricity Revenue[2]
2019 to 2023E

	2019	**2020**	**2021F**	**2022E**	**2023E**
Energy Sales					
Energy Sales (GWh)	5,846.6	5,729.0	5,719.5	5,703.4	5,670.8
Sales Change (%)	-0.5	-2.0	-0.2	-0.3	-0.6
Electricity Revenue ($000s)					
Revenue from Rates	684,179	715,627	712,338	711,562	708,398
RSA Transfers	(13,339)	(8,786)	(11,336)	(17,328)	(22,035)
Total Electricity Revenue	**670,840**	**706,841**	**701,002**	**694,234**	**686,363**

In 2019 and 2020, Newfoundland Power's energy sales declined by 0.5% and 2.0%, respectively. The decrease in 2020 energy sales was partly due to lower general service energy consumption

1 References to 2022 and 2023 with the suffix 'E' (e.g. 2022E) reflect forecast results under the Company's existing scenario and exclude the proposals in this Application. The suffix 'P' reflects forecast results that include the proposals in this Application.

2 Forecast energy sales and electricity revenue for 2021F to 2023E are based on the Company's May 2021 sales forecast. The May 2021 *Customer, Energy and Demand Forecast* is found in *Volume 2, Supporting Materials, Tab 3.*

as a result of the COVID-19 pandemic and related public health measures. Lower energy sales over the forecast period reflect declining domestic energy consumption, partially offset by a gradual recovery of general service energy sales following the COVID-19 pandemic.[3]

Other Revenue

Table 3-2 shows other revenue from 2019 to 2023E.

Table 3-2:
Other Revenue
2019 to 2023E
($000s)

	2019	**2020**	**2021F**	**2022E**	**2023E**
Pole Attachment	2,275	2,507	2,639	2,475	2,483
Provisioning Work	2,280	1,834	1,391	1,335	1,318
Customer Account Interest	1,335	1,292	1,250	1,292	1,277
Interest on RSA	(134)	(176)	(1,133)	(1,807)	(1,798)
Wheeling Charges	765	753	776	753	722
Miscellaneous	1,378	1,016	728	698	677
Total	**7,899**	**7,226**	**5,651**	**4,746**	**4,679**

The Company's other revenue for 2019 and 2020 was approximately $7.9 million and $7.2 million, respectively. This included increased provisioning work,[4] proceeds from a land sale[5] and higher interest.

[3] The energy sales decline of 0.2% in 2021 also reflects the impact of the leap year in 2020. Excluding the impact of the leap year, 2021 sales are forecast to increase by 0.2% from 2020.

[4] Increased provisioning work in 2019 and 2020 is attributable to network upgrade initiatives undertaken by telecommunications providers.

[5] In 2019, the net proceeds from a property disposition were approximately $0.5 million.

Other revenue is forecast to decline in 2021 to 2023 primarily due to higher interest credits associated with the Company's Rate Stabilization Account ("RSA") balances.[6] Excluding interest on the RSA, Newfoundland Power's other revenue is forecast to be reasonably stable at approximately $6.8 million in 2021 and an average of $6.5 million in 2022 and 2023.

3.2.2 Power Supply

Table 3-3 shows power supply costs from 2019 to 2023E.

Table 3-3:
Power Supply Costs
2019 to 2023E
($000s)

	2019	**2020**	**2021F**	**2022E**	**2023E**
Purchases from Hydro (Normalized)	456,512	470,275	465,872	465,610	461,686
Demand Management Incentive Account	(2,687)	(1,431)	(1,812)	(1,811)	(2,079)
Wholesale Rate Change Flow-Through	(8,964)	-	-	-	-
Power Supply Costs	**444,861**	**468,844**	**464,060**	**463,799**	**459,607**

Power supply costs are expected to increase by approximately $14.7 million from 2019 to 2023. This is largely attributable to an increase in Hydro's Utility Rate, partially offset by declining energy sales.[7] Power supply costs for 2019 reflect the wholesale purchased power rate change effective October 1, 2019.[8]

6 For example, the RSA had a credit balance of $15.3 million as of March 31, 2021. A credit balance reflects an amount owing to customers.
7 See Order No. P.U. 23 (2017).
8 See Order No. P.U. 31 (2019).

3.2.3 Depreciation

From 2019 to 2021, Newfoundland Power's depreciation expense reflects the methodology and depreciation rates outlined in its *2014 Depreciation Study*.[9] This depreciation study and depreciation expense formed part of the settlement agreements approved by the Board during the *2016/2017 General Rate Application* and the *2019/2020 General Rate Application*.[10]

Newfoundland Power's depreciation rates are typically reviewed every 4 to 5 years.[11] Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") performed a new depreciation study based on plant in service as of December 31, 2019 (the "2019 Study").[12]

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[9] In Order No. P.U. 13 (2013), the Board ordered Newfoundland Power to file its next depreciation study, relating to plant in service as of December 31, 2014, with its next general rate application. Gannett Fleming Valuation and Rate Consultants, LLC performed the depreciation study as required by the Board. The *2014 Depreciation Study* was filed in *Volume 3, Tab 2*, as a part of the Company's *2016/2017 General Rate Application*.

[10] See Order Nos. P.U. 18 (2016), page 7, lines 5-30, and P.U. 2 (2019), page 10, lines 5-23. The approved depreciation rates stemming from the *2014 Depreciation Study* became effective January 1, 2016.

[11] The Company's previous 4 depreciation studies were completed for plant in service at December 31, 2001, 2005, 2010 and 2014.

[12] The Gannett Fleming *2019 Depreciation Study* is found in *Volume 3, Expert Evidence, Tab 1*.

Table 3-4 compares the current depreciation rates approved by the Board in Order No. P.U. 18 (2016) to those recommended by Gannett Fleming in the 2019 Study.

Table 3-4:
Comparative Depreciation Rates (%)
Current and 2019 Study

Function	**Current**	**2019 Study**
Hydro Production	2.42	2.35
Other Production	5.31	5.51
Substation	2.94	3.10
Transmission	3.08	3.10
Distribution	3.18	3.09
General		
Computer hardware	16.90	17.12
Computer software	9.05	9.44
Transportation	9.48	9.43
Other	3.26	3.17
Composite Rate	**3.38**	**3.37**

The composite rate of depreciation recommended by Gannett Fleming in the 2019 Study is consistent with the current composite rate of depreciation used by Newfoundland Power. Changes in the individual depreciation rates for differing asset classes recommended in the 2019 Study result in lower depreciation expense for 2022 and 2023.[13]

[13] The decrease in depreciation expense related to changes in the depreciation rates is $674,000 in 2022 and $699,000 in 2023.

Table 3-5 shows depreciation expense from 2019 to 2023E reflecting adoption of the results of the 2019 Study commencing in 2022.

Table 3-5:
Depreciation Expense
2019 to 2023E
($000s)

	2019	2020	2021F	2022E	2023E
Depreciation[14]	62,066	64,982	67,739	70,956	75,252

Increases in annual depreciation expense over the period 2019 to 2023 are substantially the result of the Company's annual capital investment in the electrical system. Depreciation expense in 2022 and 2023 includes recovery of an accumulated reserve variance of approximately $1.9 million a year over the average remaining service life of the affected asset classes as recommended in the 2019 Study.[15]

The next depreciation study is expected to be completed in 2025 based on plant in service as of December 31, 2024.

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[14] Total depreciation expense reflects an increase of $1,206,000 in the annual amortization of the accumulated reserve amount and a decrease in expense due to new rates proposed by Gannett Fleming. The annual amortization of the accumulated reserve amount in the *2019 Depreciation Study* is $1,851,000 compared to the current annual amortization of $645,000 related to the *2014 Depreciation Study* ($1,851,000 - $645,000 = $1,206,000). The decrease in expense due to new rates is $674,000 in 2022 and $699,000 in 2023. The total impact of adopting the results of the 2019 Study on depreciation expense is a net increase of $532,000 ($1,206,000 - $674,000) in 2022 and $507,000 ($1,206,000 - $699,000) in 2023.

[15] Recovery of the reserve variance on this basis is consistent with the amortized recovery approved by the Board in Order No. P.U. 18 (2016), page 7, lines 26-30. The accumulated reserve variance included in the *2016/2017 General Rate Application* was outlined in the *2014 Depreciation Study* and included recovery of approximately $12.2 million over the average remaining service life of the affected asset classes.

3.2.4 Employee Future Benefits

General

Newfoundland Power maintains plans for its employees that provide benefits upon retirement. These plans fall into 2 broad categories: (i) pension plans; and (ii) other post-employment benefits ("OPEB") plans.

Table 3-6 shows employee future benefits expense from 2019 to 2023E.

Table 3-6:
Employee Future Benefits Expense
2019 to 2023E
($000s)

	2019	**2020**	**2021F**	**2022E**	**2023E**
Pension Expense	3,335	7,863	6,958	912	(1,780)
OPEB Expense	6,240	6,528	7,720	7,833	7,939
Total Expense	**9,575**	**14,391**	**14,678**	**8,745**	**6,159**

Newfoundland Power expects total employee future benefits expense to decrease by approximately $3.4 million from 2019 to 2023.

Pensions

Newfoundland Power maintains both defined benefit and defined contribution pension plans.[16]

[16] Newfoundland Power's defined benefit pension plan was created in 1984 and closed to new entrants in 2004. There were 194 active employees participating in this plan as at December 31, 2020. In addition, at December 31, 2020, the defined benefit pension plan provided retirement income to a total of 780 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.

The Company's defined benefit pension plan has been closed to new entrants since 2004. Employees hired since that time participate in a defined contribution pension plan, which provides retirement income based upon the contributions made by the Company and employee, together with the accrued returns on those contributions.

Table 3-7 shows the components of Newfoundland Power's pension expense from 2019 to 2023E.

Table 3-7:
Pension Expense
2019 to 2023E
($000s)

	2019	**2020**	**2021F**	**2022E**	**2023E**
Defined Contribution Pension Plan	2,370	2,711	2,821	3,057	3,318
Defined Benefit Pension Plan	965	5,152	4,137	(2,145)	(5,098)
Total Pension Expense	**3,335**	**7,863**	**6,958**	**912**	**(1,780)**

Increased defined contribution pension plan expense of approximately $948,000 from 2019 to 2023 reflects an increased number of employees, increases in employer matching rates and increases in compensation.[17]

[17] The current collective agreements for the Craft and Clerical bargaining units included negotiated increases in contribution rates to employee retirement savings plans. These increases were applicable to all employees contributing to retirement savings plans with the Company. Under Clause 17.05, the required contributions increased to 2.0% from 1.5%, effective date of signing, May 6, 2019. Under Clause 17.09, the required contributions increased to 6.25% from 5.75% effective date of signing, May 6, 2019, and to 6.50% on January 1, 2021.

Defined benefit pension plan expense reflects: (i) the results of the Company's latest actuarial pension funding valuation;[18] (ii) returns on plan assets to 2020;[19] and (iii) a stable forecast discount rate.[20] Defined benefit pension expense is forecast to decrease by approximately $6.1 million between 2019 and 2023. The decline reflects lower interest costs and changes in actuarial gains and losses.[21]

OPEB

Table 3-8 shows OPEB expense from 2019 to 2023E.

Table 3-8:
OPEB Expense
2019 to 2023E
($000s)

	2019	2020	2021F	2022E	2023E
OPEB Expense	6,240	6,528	7,720	7,833	7,939

OPEB expense is forecast to increase by approximately $1.7 million between 2019 and 2023. This reflects: (i) full amortization of past service credits by December 31, 2020;[22] and (ii) a lower forecast discount rate.[23]

18 The Company typically completes an actuarial pension funding valuation every 3 years. The latest valuation was completed as at December 31, 2019.

19 In 2019 and 2020, the expected returns on defined benefit pension plan assets were 5.25% and 4.75%, respectively. Expected returns are 4.5% for 2021 through 2023.

20 In 2019 and 2020, the discount rates used for expense projections were 3.8% and 3.1%, respectively. A discount rate of 2.6% is forecast for 2021 through 2023.

21 In 2019, the amortization of an actuarial loss was $2.6 million. In 2023, there are no forecast amortizations of actuarial losses.

22 The Company amended its OPEBs plan effective January 1, 2011. The key plan amendments included the introduction of a 50% member-paid cost sharing arrangement for retirees over the age of 65, the removal of a $5,000 annual benefit cap, and the introduction of drug dispensing fees. The impact of this amendment was amortized evenly over the next 10 years, which was the expected average remaining service period to qualify for a full pension.

23 In 2019 and 2020, the discount rates used for expense projections were 3.9% and 3.2%, respectively. A discount rate of 2.7% is forecast for 2021 through 2023.

3.2.5 Finance Charges

Table 3-9 shows average debt, finance charges and average cost of debt from 2019 to 2023E.[24]

Table 3-9:
Finance Charges
2019 to 2023E

	2019	2020	2021F	2022E	2023E
Average Debt ($000s)	616,343	629,385	653,961	678,353	699,501
Average Cost of Debt (%)	5.68	5.83	5.31	5.10	4.71
Finance Charges ($000s)	35,032	36,704	34,695	34,587	32,917

Newfoundland Power's average debt is expected to increase by approximately $83 million from 2019 to 2023. The increase in average debt is primarily to finance capital expenditures necessary to maintain system reliability and to provide required service to customers.[25]

The Company's average cost of debt from 2019 to 2023 is expected to decline by 0.97%. This primarily reflects lower average coupon rates on the Company's first mortgage bonds.[26]

Newfoundland Power's finance charges are expected to decrease by approximately $2 million from 2019 to 2023. The decrease primarily reflects a lower average cost of debt and higher Allowance for Funds Used During Construction ("AFUDC") associated with the Customer

[24] Table 3-9 shows regulated finance charges, which exclude interest on security deposits as they are not included in the determination of revenue requirements.

[25] Newfoundland Power's annual capital expenditures for the period 2019 through 2021 were approved by the Board in Order Nos. P.U. 35 (2018), P.U. 5 (2019), P.U. 6 (2019), P.U. 36 (2019), P.U. 5 (2020), P.U. 37 (2020), P.U. 10 (2021), and P.U. 12 (2021).

[26] This is a result of higher interest rate debt being retired and replaced with lower interest rate debt. For example, in April 2020, the Company issued $100 million in Series AQ First Mortgage Bonds which had a coupon rate of 3.608%. Net proceeds from the issue were used to repay short-term borrowings and, in October 2020, for repayment of $30 million in Series AG First Mortgage Bonds which had a coupon rate of 9.0%.

Service System Replacement Project. These factors are partially offset by increased finance charges associated with higher average debt in 2023.

3.2.6 Income Taxes

Table 3-10 shows income taxes from 2019 to 2023E.

Table 3-10:
Income Taxes
2019 to 2023E

	2019	2020	2021F	2022E	2023E
Income Taxes ($000s)	18,324	19,338	17,698	15,384	13,294
Effective Income Tax Rate (%)[27]	28.76	29.39	29.00	28.46	27.78

Newfoundland Power's effective income tax rate is forecast to remain stable through the 2019 to 2023 period.

3.2.7 Returns

Table 3-11 shows the approved, actual and forecast rates of return on rate base, and the actual and forecast rates of return on common equity from 2019 to 2023E.

Table 3-11:
Rates of Return
2019 to 2023E
(%)

	2019	2020	2021F	2022E	2023E
Return on Rate Base					
Midpoint (Approved)	7.01	7.04	6.65	-	-
Actual / Forecast	6.97	7.04	6.46	5.90	5.23
Return on Common Equity	8.79	8.93	8.24	7.16	6.34

[27] The effective income tax rate reflects enacted tax rates at the time of preparing this Application.

Newfoundland Power's rate of return on rate base was within the range approved by the Board for 2019 and 2020.[28] For 2021, the Company is forecasting a return on rate base slightly below the range approved by the Board.[29]

The forecast rates of return on rate base and rates of return on equity for 2022 to 2023 reflect the eroding financial performance of the Company over the forecast period.

3.2.8 Credit Metrics

Newfoundland Power maintains an investment grade credit rating from 2 independent rating agencies: DBRS Limited ("DBRS") and Moody's Investors Service ("Moody's").[30] A review of the Company's credit metrics forms a part of the DBRS and Moody's annual credit rating assessments.

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%).[31] Similarly,

[28] In Order No. P.U. 2 (2019), the Board approved a rate of return on rate base for 2019 of 7.01% in a range of 6.83% to 7.19% and the rate of return on rate base for 2020 of 7.04% in a range of 6.86% to 7.22%.

[29] In Order No. P.U. 36 (2020), the Board approved a rate of return on rate base for 2021 of 6.65% in a range of 6.47% to 6.83%.

[30] The most recent DBRS and Moody's credit rating reports are filed in *Volume 1, Application, Company Evidence and Exhibits, Exhibit 4.* DBRS has consistently rated both Newfoundland Power and its first mortgage bonds with an 'A' credit rating. Moody's Long Term Rating for Newfoundland Power is 'Baa1'.

[31] See Exhibit 4 in *Volume 1, Application, Company Evidence and Exhibits, Moody's,* page 8.

DBRS considers Newfoundland Power's stable and supportive regulatory environment and strong financial profile as key credit strengths.[32]

Table 3-12 shows Newfoundland Power's credit metrics from 2019 to 2023E.[33]

Table 3-12:
Credit Metrics
2019 to 2023E

	2019	2020	2021F	2022E	2023E
Pre-tax Interest Coverage (times)	2.4	2.4	2.4	2.2	2.0
Cash Flow Interest Coverage (times)[34]	4.0	4.6	4.9	4.7	5.0
Cash Flow Debt Coverage (%)[35]	17.4	21.1	20.6	18.7	19.2

Under existing customer rates, Newfoundland Power's pre-tax interest coverage is expected to decline from 2.4 times in 2019 to 2.0 times in 2023, reflecting the deterioration of Newfoundland Power's pre-tax earnings over that time period. This has implications for Newfoundland Power's future financing flexibility.

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32 See Exhibit 4 in *Volume 1, Application, Company Evidence and Exhibits, DBRS*, page 2.

33 Cash flow metrics from 2020 to 2023 are positively impacted by the combination of current marginal energy costs and Newfoundland Power's declining energy sales. With sales in decline, the Company avoids purchasing power at a marginal rate of 18.165¢/kWh. This is substantially higher than lost sales revenue, which reflects an average supply cost rate of 7.439¢/kWh. This dynamic results in a positive impact on operating cash flow pre-working capital. Ultimately, any savings are credited to customers via the Company's Energy Supply Cost Variance Clause. This dynamic is temporary as marginal energy costs are forecast to be substantially lower upon commissioning of the Muskrat Falls Project.

34 Excluding the impact of current energy supply cost variances, Newfoundland Power's cash flow interest coverage would be 4.0 times in 2022 and 4.2 times in 2023.

35 Excluding the impact of the current energy supply cost variances, the Company's cash flow debt coverage would be 15.2% in 2022 and 15.5% in 2023.

The trust deed that secures the first mortgage bonds requires, in effect, an interest coverage of 2.0 times or higher for the Company to issue additional bonds (the "Bond Earnings Test").[36] Based on 2023 pre-tax earnings, Newfoundland Power's Bond Earnings Test would be 1.9 times. Under existing customer rates, the Company's ability to issue first mortgage bonds would be limited.

Newfoundland Power's financial outlook, combined with its business risk, can affect the Company's ability to maintain current credit ratings and access capital markets at reasonable costs.

3.3 COST OF CAPITAL

In this Application, the Board will consider Newfoundland Power's cost of capital for 2022 and 2023. The expert evidence filed with this Application indicates a fair return for Newfoundland Power for 2022 and 2023 comprises: (i) a capital structure consisting of 45% common equity; and (ii) a return on equity of 9.8%.

The Board typically reviews Newfoundland Power's cost of capital every 3 years. In determining a fair return, the Board has consistently applied principles prescribed by the Electrical Power Control Act, 1994, the Public Utilities Act, and the fair return standard. The Board has historically interpreted a fair return as one that is: (i) commensurate with returns

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[36] Article 6.2 of the trust deed securing Newfoundland Power's first mortgage bonds provides: *"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."*

on investments of similar risk; (ii) sufficient to ensure the utility's financial integrity; and (iii) sufficient to attract necessary capital.

This section of evidence provides an overview of factors affecting the Company's business risk. Overall, the evidence shows that the business risks facing Newfoundland Power have not materially changed since the Board last considered the Company's business risks in 2018.

This section of evidence also reviews Newfoundland Power's credit metrics under the Company's existing scenario and with the proposals in this Application. The proposals in this Application, which include a return on equity of 9.8% based on a capital structure with a target equity ratio of 45%, are consistent with the fair return standard.

The Board will also consider whether financial markets support the use of an automatic adjustment formula to adjust annually the Company's return on rate base to reflect changes in the cost of equity for years following 2023.

Use of the Automatic Adjustment Formula has been suspended since 2012 due to low long Canada bond yields. Current yields remain low. Newfoundland Power therefore proposes continued suspension of the Formula. The expert evidence filed with this Application also recommends continued suspension of the Automatic Adjustment Formula.

3.3.1 Regulatory Framework

Background

Newfoundland Power is required to invest capital in the electrical system to ensure the continued delivery of reliable service to customers. Each year, the Company's capital expenditures for the ensuing year are considered and approved by the Board. The source of this capital investment is a combination of common equity and debt financing.[37] The Company's cost of capital depends on: (i) the amount of common equity and debt used to finance capital investment; (ii) the rate of return on common equity; and (iii) the interest rates on outstanding debt.

The Board determines the proportion of equity that can be used in Newfoundland Power's capital structure for ratemaking purposes. The Board also determines the Company's rate of return on equity used to establish customer rates.

Interest rates on the Company's debt are determined by financial markets. Interest on short-term debt is primarily based upon prime lending rates. Interest on long-term debt is determined by capital markets at the time the debt is issued. Debt rating agencies, such as Moody's and DBRS, facilitate financial markets by providing credit ratings that are indicative of the risk of the investment.[38]

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[37] Newfoundland Power has both short-term and long-term debt. Short-term debt consists of a $100 million committed revolving term facility and a $20 million demand facility. The Company's long-term debt primarily consists of first mortgage bonds.

[38] Moody's Baseline Credit Assessments ("BCA") reflect Moody's opinions of issuers' standalone intrinsic strength, absent any extraordinary support from an affiliate or a government. BCA is measured on a 9-step scale from 'c' to 'aaa.' Newfoundland Power is currently rated baa1. Moody's states: *"Issuers assessed baa are judged to have medium-grade intrinsic, or standalone, financial strength, and thus subject to moderate credit risk and, as such, may possess certain speculative credit elements absent any possibility of extraordinary support from an affiliate or a government."*

Newfoundland Power as a debt issuer, and its long-term debt, have held investment grade ratings from 2 credit rating agencies for over 2 decades. The Company's capital structure and rate of return on equity are measures of financial risk considered by credit rating agencies in determining an appropriate credit rating for Newfoundland Power. Capital structure, rate of return on equity, and credit ratings are therefore interrelated.

Legislative Context

Newfoundland Power is regulated under: (i) the *Electrical Power Control Act*, *1994*; and (ii) the *Public Utilities Act*. The legislative construct for Newfoundland Power is broadly consistent with those of other investor-owned utilities in Canada.

The *Electrical Power Control Act, 1994* establishes the provincial power policy. Section 3(a)(iii) states:

> *"It is declared to be the policy of the province that… the rates to be charged, either generally or under specific contracts, for the supply of power within the province… should 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."*

The *Public Utilities Act* establishes the legislative powers of the Board. Section 80 states:

> *"(1) 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…"*
>
> *"(2) The return shall be in addition to those expenses that the board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the board according to this Act and the rules and regulations of the board."*

The Fair Return Standard

The Board is guided by the fair return standard in determining an appropriate capital structure and return on equity for Newfoundland Power. In Order No. P.U. 32 (2007), the Board described the fair return standard 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 assure 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."*[39]

The Board has applied its view of the fair return standard for Newfoundland Power in a number of proceedings. In Order No. P.U. 2 (2019), the Board stated:

> *"In Order Nos. P.U. 43(2009), P.U. 13(2013) and P.U. 18(2016) the Board explained that 'to be considered fair the return must be commensurate with the return on investments of similar risk and sufficient to assure financial integrity and to attract necessary capital.' All three of these requirements must be met and no one requirement takes precedence over the other two."*[40]

The Board's view of the fair return standard is one that commonly accepted throughout North America.

Capital Structure

Newfoundland Power's targeted capital structure consists of 45% common equity for ratemaking purposes. The Company's capital structure has not changed in over 2 decades and has

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[39] See Order No. P.U. 32 (2007), Appendix A, page 6.
[40] See Order No. P.U. 2 (2019), page 12, lines 9-12.

contributed to the Company's continued access to capital markets on reasonable terms. The Board has acknowledged that a fair return cannot be determined independently of a utility's capital structure.[41]

The significance of capital structure in determining a fair return has also been recognized by the Newfoundland and Labrador Court of Appeal:

> *"[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 judgment'. 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."*[42]

The Board's views of the appropriateness of Newfoundland Power's longstanding capital structure have remained consistent since it was first approved in 1996. In Order No. P.U. 19 (2003), the Board stated:

> *"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."*[43]

[41] See Order No. P.U. 18 (2016), page 11, lines 4-5.
[42] See *The Stated Case*, June 15, 1998, Newfoundland and Labrador Court of Appeal, paragraphs 134-135.
[43] See Order No. P.U. 19 (2003), page 45.

Order No. P.U. 18 (2016) was issued following a review of Newfoundland Power's capital structure. In that order, the Board maintained Newfoundland Power's common equity ratio for rate setting purposes.[44]

Newfoundland Power's capital structure formed part of the settlement agreement reached in relation to the Company's *2019/2020 General Rate Application*.[45] In Order No. P.U. 2 (2019), the Board maintained the Company's capital structure for rate setting purposes and observed:

> *"In terms of capital structure, the Board has accepted a capital structure of 45% equity for rate setting for Newfoundland Power since 1996. Newfoundland Power's capital structure is recognized by credit rating agencies as a strength, which positively impacts its credit worthiness."*[46]

3.3.2 Risk Assessment

General

Newfoundland Power's cost of capital is the rate of return investors could expect to earn if they invested in securities of equal risk. In regulatory practice, the opportunity cost of capital is integral to the concept of a fair return. For this reason, cost of capital is essentially a relative concept. The accepted relative measure for determining a business' cost of capital is risk.

In 2018, Newfoundland Power observed certain business risks had become more pronounced. The provincial economic outlook had deteriorated, energy sales had declined, and costs related to the Muskrat Falls Project had increased.[47]

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[44] See Order No. P.U. 18 (2016), page 25, lines 14-15.
[45] See Order No. P.U. 2 (2019), page 12, lines 20-27.
[46] See Order No. P.U. 2 (2019), page 12, lines 20-22.
[47] See Newfoundland Power's *2019/2020 General Rate Application, Volume 1, Company Evidence, Section 3.3.2 2018 Risk Assessment,* page 3-20 *et seq.*

The principal risks to which Newfoundland Power is exposed have not changed materially since 2018. As of 2021, the provincial economic outlook remains weak, energy sales have further declined and the Muskrat Falls Project continues to pose a risk to the least-cost delivery of reliable service to customers.

The Company's risk profile continues to be defined by other longstanding factors. These factors include the Company's small size, service territory demographics, operating environment, regulatory mechanisms, and limited cost flexibility.

Provincial Economy

The economic outlook for Newfoundland Power's service territory is expected to remain weak compared to the rest of Canada.

Table 3-13 compares the economic outlooks for Newfoundland and Labrador and Canada from 2021 to 2025.

Table 3-13:
Economic Outlook
Newfoundland and Labrador vs. Canada
(2021 to 2025)[48]

Economic Indicator	NL	Canada	Difference
GDP	2.1%	2.3%	-0.2%
Labour Force	-0.3%	0.9%	-1.2%
Employment	0.0%	1.5%	-1.5%
Household Disposable Income	2.1%	2.9%	-0.8%
Retail Sales	2.5%	2.4%	0.1%
Housing Starts	-4.2%	-1.9%	-2.3%

[48] Based on The Conference Board of Canada medium-term outlook published March 18, 2021. See *Volume 2, Supporting Materials, Tab 3, Customer Energy and Demand Forecast, Attachment 1*.

The economic outlook for Newfoundland and Labrador lags behind that of Canada across key economic indicators over the period 2021 to 2025.

Provincial GDP growth is forecast to be approximately 2.1% annually from 2021 to 2025. This is less than the national GDP growth forecast over the same period.

Housing starts in Newfoundland and Labrador declined by 79% over the period 2010 to 2020.[49] Housing starts in the province are forecast to decline more than twice as fast as the national average from 2021 to 2025.[50]

The Conference Board of Canada has observed that Newfoundland and Labrador has the highest unemployment rate in Canada.[51]

In 2021, the Atlantic Provinces Economic Council ("APEC") observed that:

> *"The provincial labour force has been shrinking since 2013 creating a labour challenge as the remaining baby boomers retire. For every ten people retiring from the labour force (aged 55-64 years), only 7 youth (15-24 years) currently enter, compared with 16 new entrants two decades ago."*[52]

[49] Housing starts in Newfoundland and Labrador totaled 3,606 in 2010 and 763 in 2020 ((763 – 3,606) / 3,606 = -0.79, or -79%). See *Volume 2, Supporting Materials, Tab 3, Customer Energy and Demand Forecast, Appendix A.*

[50] From 2021 to 2025, housing starts are forecast to decline by an average of 4.2% annually in Newfoundland and Labrador and 1.9% in Canada (4.2 / 1.9 = 2.2).

[51] See The Conference Board of Canada, *Newfoundland and Labrador's Two-Year Outlook*, March 18, 2021, page 7.

[52] See APEC Commentary, *Challenges and Prospects for Newfoundland and Labrador's Economy,* January 28, 2021, page 6.

APEC further observed that:

> *"The province's net debt is currently projected to be $16 billion this year, about $31,500 per person. This is the largest debt per person in the country, 16% higher than the next highest province, Ontario, and more than double that of Alberta."*[53]

The weak economic outlook for Newfoundland and Labrador presents risks to Newfoundland Power's ability to recover its investment in long-life utility assets and earn a fair return.

Service Territory Demographics

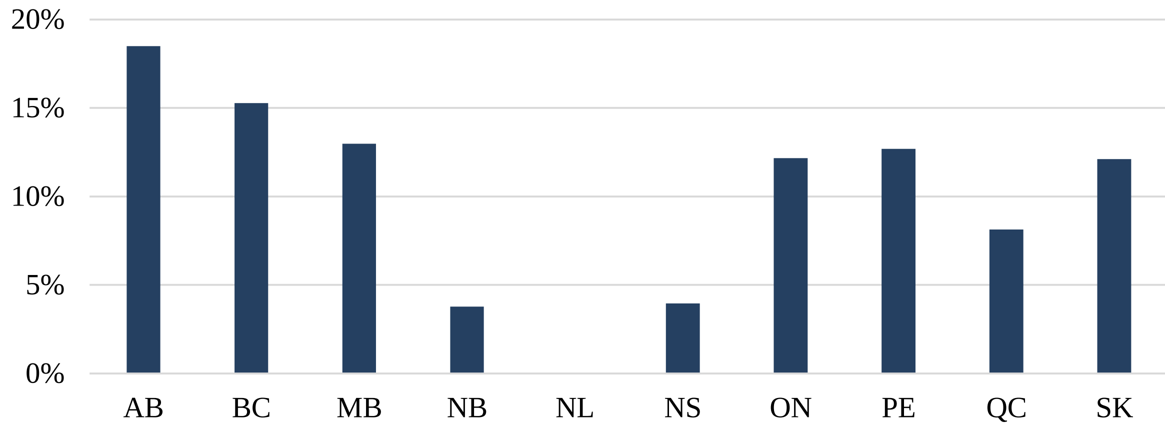
The population of Newfoundland Power's service territory is declining, becoming more concentrated in urban areas, and aging faster than national trends.

Newfoundland and Labrador is the only Canadian province to experience no population growth over the last decade.

[53] See APEC Commentary, *Challenges and Prospects for Newfoundland and Labrador's Economy,* January 28, 2021, page 8.

Figure 3-1 shows population growth for each Canadian province over the period 2010 to 2020.[54]

Figure 3-1:
Provincial Population Growth
2010-2020



The population of Newfoundland and Labrador was approximately 522,000 in both 2010 and 2020. This compares to population growth in other provinces ranging from 3.8% in New Brunswick to 18.5% in Alberta over the same period. Newfoundland and Labrador was the only province to experience population decline over the most recent 5-year period.[55]

The Conference Board of Canada forecasts population decline of approximately 0.8% per year for Newfoundland and Labrador from 2021 to 2025.[56] This compares to national population growth of 1.0% per year over the same period.[57]

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54 See Statistics Canada, Table 17-10-0005-01.

55 The population of Newfoundland and Labrador was approximately 528,000 in 2015 and 522,000 in 2020. See Statistics Canada, Table 17-10-0005-01.

56 The Conference Board of Canada forecasts the provincial population to be approximately 520,000 in 2021 and 503,000 in 2025 ((503,000 – 520,000) / 520,000 / 4 = -0.008, or -0.8%).

57 The Conference Board of Canada forecasts the Canadian population to be approximately 38.3 million in 2021 and 39.8 million in 2025 ((39.8 million – 38.3 million) / 38.3 million / 4 = 0.010, or 1.0%).

Newfoundland and Labrador's population is becoming more concentrated in the province's largest urban area, the Northeast Avalon.

The population of the Northeast Avalon increased by approximately 8% over the period 2010 to 2020. This compares to a 5% decline in population for the remainder of the province over the same period.[58]

In 2020, approximately ½ of Newfoundland Power's customers and ¼ of the Company's distribution assets were located on the Northeast Avalon. The remaining ¾ of distribution assets served customers in more rural areas of the province.

Concentration of the province's population on the Northeast Avalon is projected to continue. The Provincial Government projects that the Northeast Avalon will increase in population by approximately 13% by 2040. The population of more rural areas of the province is projected to decline. For example, by 2040 the populations of the Bonavista and Burin peninsulas are projected to decline by approximately 12% and 21%, respectively.[59]

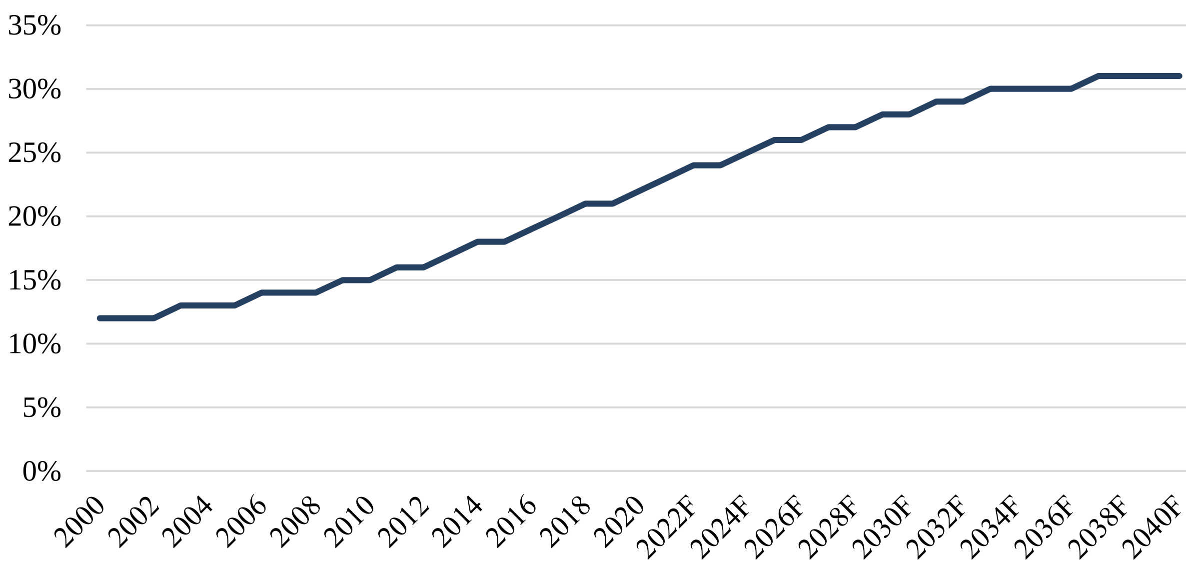
Newfoundland and Labrador's population is older than the Canadian population.

[58] See Statistics Canada, Tables 17-10-0135-01 and 17-10-0139-01.
[59] See Government of Newfoundland and Labrador, Department of Finance, *Population Projections – Demographic Overview*, updated November 2020.

The median age of the Newfoundland and Labrador population was 6.5 years higher than the Canadian population in 2020.[60] Residents aged 65 and older account for 18% of the Canadian population, compared to 22% of the Newfoundland and Labrador population.[61]

Figure 3-2 shows the percentage of the Newfoundland and Labrador population aged 65 and older over the period 2000 to 2040F.[62]

Figure 3-2:
Newfoundland and Labrador
Percentage of Population Aged 65 and Older
2000 to 2040F



Residents aged 65 and older comprised approximately 12% of the provincial population in 2000 and 22% of the provincial population in 2020. Residents aged 65 and older are projected to comprise approximately 31% of the provincial population by 2040.

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[60] The median age of the Newfoundland and Labrador population was 47.4 in 2020, compared to a national median age of 40.9. See Statistics Canada, Table 17-10-0005-01.

[61] See Statistics Canada, Table 17-10-0005-01.

[62] See Government of Newfoundland and Labrador, Department of Finance, *Population Projections for Newfoundland and Labrador, Medium Scenario*, November 2020.

The Provincial Government has observed that:

> *"All Canadian provinces are faced with an aging population and are very concerned with the challenges this presents for the delivery and financing of social services. However, in Newfoundland and Labrador, in addition to low fertility rates, the aging phenomenon has been exacerbated by high rates of out-migration among young people in the most fertile child-bearing age range. As a result, the province's population has aged much more rapidly than any other province in the country over the last 50 years. The province's median age has gone from five years lower than Canada's in 1971 to over six years higher than Canada's in 2020. The aging trend will likely continue for years to come."*[63]

These demographic conditions can be expected to exert pressure on the provincial economy, government service delivery and Newfoundland Power's ability to recover its investment in long-life utility assets.

For example, APEC has observed that:

> *"The provincial population – already the oldest in Canada with the highest proportion of seniors – is aging, implying increased demand for senior care and higher health care costs. The province's population is also spread over a huge area, with the lowest population density among the provinces, creating a challenge to maintain public (and private) services and infrastructure."*[64]

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[63] See Government of Newfoundland and Labrador, Department of Finance, *Population Projections – Demographic Overview*, updated November 2020.

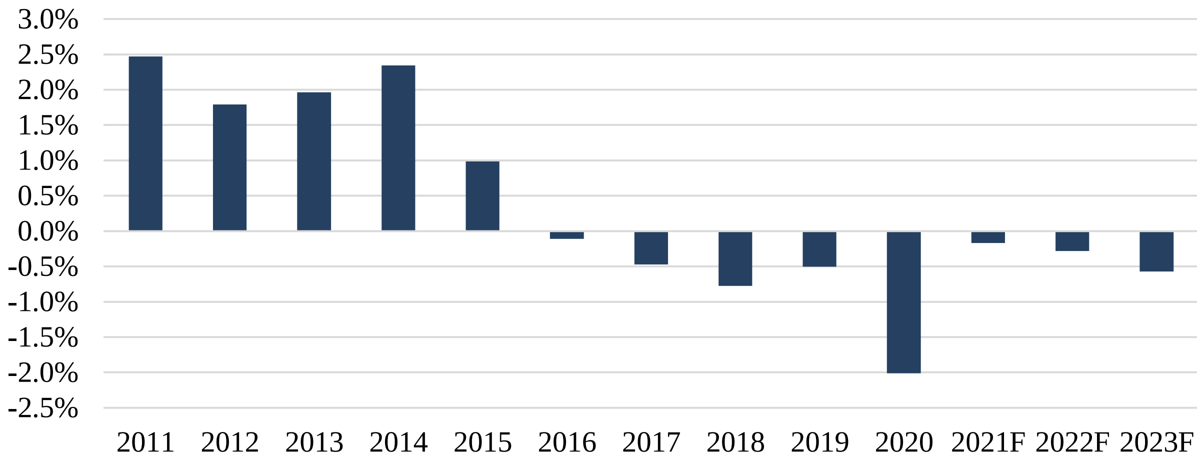
[64] See APEC Commentary, *Challenges and Prospects for Newfoundland and Labrador's Economy,* January 28, 2021, page 6.

Energy Sales

Newfoundland Power's energy sales have declined annually since 2016.

Figure 3-3 shows Newfoundland Power's annual change in energy sales for the period 2011 to 2023F.

Figure 3-3:
Annual Change in Energy Sales
(2011-2023F)



Over the 5-year period 2016 to 2020, Newfoundland Power's energy sales declined by an average of approximately 0.8% per year.[65] This compares to energy sales growth of approximately 1.9% per year over the previous 5-year period.[66] The sharp decline in energy sales in 2020 is partly attributable to the COVID-19 pandemic.[67]

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[65] (-0.1% + -0.5% + -0.8% + -0.5% + -2.0%) / 5 = -0.8%.

[66] (2.5% + 1.8% + 2.0% + 2.3% + 1.0%) / 5 = 1.9%.

[67] Newfoundland Power's energy sales declined by 2.0% in 2020. This represents the largest year-over-year decline in the Company's energy sales. Newfoundland Power's energy sales in 2020, specifically in the general service and domestic categories, were affected by the public health measures introduced by the Provincial Government to manage the COVID-19 pandemic. For more information, see *Volume 2, Supporting Materials, Tab 3, Customer, Energy and Demand Forecast, Section 4.1 2020 Energy Sales.*

Newfoundland Power forecasts average annual energy sales of approximately 5,698 GWh over the period 2021 to 2023. This is approximately 2.8% less than the Company's average annual energy sales over the period 2016 to 2020.[68]

The decline in energy sales reflects weak economic conditions, population and demographic changes, and customer usage patterns in Newfoundland Power's service territory.

Declining energy sales make the Company less appealing to financial markets than utilities with higher growth potential.

Muskrat Falls

Newfoundland Power is dependent upon Hydro for the bulk generation and transmission of electricity to its customers. Hydro has the exclusive right to sell electricity to Newfoundland Power and Industrial Customers on the Island Interconnected System.[69] The cost of purchasing electricity from Hydro is Newfoundland Power's single largest cost.

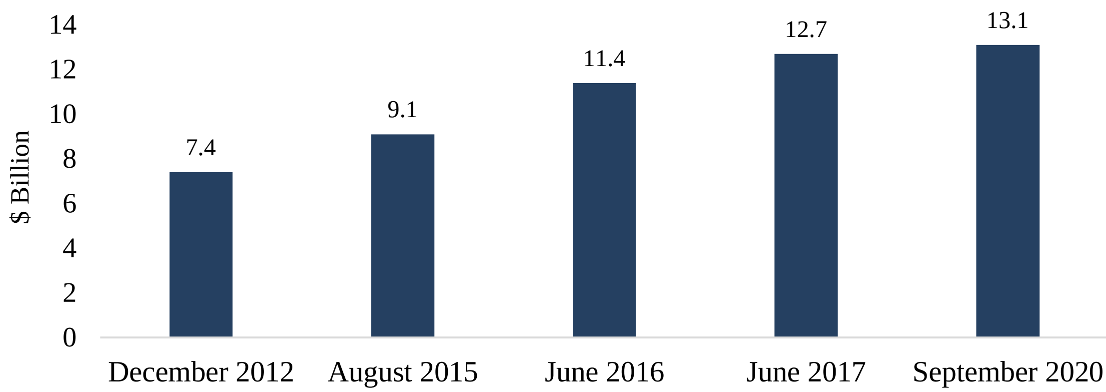
[68] Newfoundland Power's energy sales averaged approximately 5,865 GWh per year over the period 2016 to 2020 ((5,698 – 5,865) / 5,865 = -0.028, or -2.8%).

[69] Provincial Government legislation dated December 22, 2012 granted Hydro the exclusive right to sell electricity to Newfoundland Power and Industrial Customers on the island of Newfoundland.

Commissioning of the Muskrat Falls Project is expected to affect both the cost and reliability of the service provided to Newfoundland Power's customers.

Figure 3-4 shows the estimated cost of the Muskrat Falls Project since sanctioning in 2012.

Figure 3-4:
Muskrat Falls Projected In-Service Capital Cost
2012 to 2020



The cost of the Muskrat Falls Project is substantial compared to the existing electrical system in the province. As of September 2020, the estimated cost of the Muskrat Falls Project is $13.1 billion.[70] This is over 3 times the combined book value of the current utility investment of Hydro and Newfoundland Power.[71]

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70 See Nalcor Energy, *Muskrat Falls Project Cost and Schedule Update*, September 28, 2020, page 10.
71 Newfoundland Power's forecast average rate base at year-end 2020 was approximately $1.2 billion as shown in Return 3 of Newfoundland Power's *2020 Annual Report* filed with the Board on March 31, 2021. Hydro's average rate base at year-end 2019 was approximately $2.3 billion, as shown in Hydro's *2021 Capital Budget Application* (see Section I: 2017, 2018, 2019 Average Rate Base (Revision 2), page I-1) ($13.1 billion / ($1.2 billion + $2.3 billion) = 3.7).

The Provincial Government issued a Reference to the Board in 2018 to assess options to mitigate the customer rate impacts associated with the Muskrat Falls Project.[72] The Board assessed options to reduce costs to customers and increase revenues. The Board found that, even if all recommended sources of rate mitigation are applied, it is estimated that rates will still increase by over 50% and over $400 million would be required annually to keep domestic rates at or below 13.5 ¢ per kWh.[73]

The Board found that there may be additional rate mitigation potential associated with Muskrat Falls Project financing.[74] In February 2020, the Provincial Government entered into negotiations with the Federal Government to undertake a financial restructuring of the project.[75]

Increases in supply costs related to the Muskrat Falls Project could be expected to put pressure on Newfoundland Power's ability to earn a fair return.

The reliability of supply from the Muskrat Falls Project is currently under review by the Board.

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[72] The Reference questions were threefold: (i) options to reduce the impact of Muskrat Falls Project costs on electricity rates; (ii) the amount of energy and capacity from the Muskrat Falls Project required to meet Island Interconnected load and the remaining surplus energy and capacity available for other uses such as export and load growth; and (iii) the potential electricity rate impacts of the options identified. See correspondence from Minister Siobhan Coady to the Board, dated September 5, 2018.

[73] See the Board's *Final Report on Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, page iv.

[74] Examination of options to financially restructure the project was suspended during the Board's review when the Provincial Government engaged in rate mitigation discussions with the Federal Government. See the Board's *Final Report on Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, pages iii to iv.

[75] An agreement to pursue a financial restructuring of the project was reached between the Provincial Government and Federal Government in February 2020. See *Provincial and Federal Governments Collaborate to Protect Residents from Negative Impacts of Muskrat Falls,* February 10, 2020.

The Muskrat Falls Project is located in Labrador and was designed to supply Newfoundland Power's customers by way of the 1,100 kilometre Labrador-Island Link ("LIL") HVDC transmission line. The reliability of the LIL is among the issues under review. For example, the LIL experienced damage in January 2021 due to ice accumulation and additional equipment failures in February 2021.[76] Substantial time was required to return the LIL to normal operation following these events.[77]

At the time of sanctioning the Muskrat Falls Project in 2012, it was anticipated that commissioning of the project would enable the retirement of Hydro's Holyrood Thermal Generating Station ("Holyrood").[78] The potential retirement of Holyrood is also under review.

Reliability of supply from the Muskrat Falls Project affects Newfoundland Power's business risk from 2 perspectives.

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[76] See pages 1 and 2 of Hydro's correspondence to the Board regarding *Reliability and Resource Adequacy Study Review – Labrador-Island Link Monthly Update – February 2021 Further Update*, dated February 15, 2021.

[77] With respect to the January 2021 damage, Hydro indicated that critical repairs were completed from January 12, 2021 through to February 24, 2021 (see page 6 of Hydro's correspondence to the Board regarding the *Reliability and Resource Adequacy Study Review – Labrador-Island Link Monthly Update – March 2021 – Board Questions – Hydro's Response,* dated March 30, 2021). With respect to the February 2021 equipment failures, Hydro indicated that commissioning work was paused on February 7, 2021 and recommenced on February 24, 2021 (see page 2 of Hydro's correspondence to the Board regarding *Reliability and Resource Adequacy Study Review – Labrador-Island Link Monthly Update – March 2021*, dated March 4, 2021).

[78] Holyrood is a 490 MW thermal generating station located approximately 40 kilometres from Newfoundland Power's load centre on the Northeast Avalon. Prior to development of the Muskrat Falls Project, Holyrood was the second largest source of supply for Newfoundland Power's customers.

First, an outage to the LIL during the winter season could result in a shortfall of up to approximately 400 MW on the Island Interconnected System.[79] This could result in large-scale customer outages over a prolonged period of time.[80] Such a scenario would impede Newfoundland Power's ability to provide adequate service and pose serious health and safety risks to the Company's customers. Under this scenario, Newfoundland Power could be expected to incur additional costs to continue serving its customers with available electricity supply.[81]

Second, inadequate supply reliability could result in the need for additional investments to improve reliability, including investments in additional sources of supply or investments to improve the reliability of the LIL.[82] Such investments could be expected to contribute to higher customer rates.[83]

Cost Flexibility

Purchased power costs and fixed costs, including finance charges and depreciation costs, comprise an increasing proportion of Newfoundland Power's revenues on a ¢ per kWh basis.

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[79] See Request for Information NP-NLH-036 filed in relation to Hydro's *Reliability and Resource Adequacy Study Review*. By comparison, during widespread customer outages in January 2014, known as #DarkNL, Newfoundland Power was required to rotate approximately 100 MW of customer load to address a supply shortfall.

[80] In correspondence to Hydro dated March 25, 2021, the Board raised concerns regarding the findings of a report by Asim Haldar, PhD, P.Eng, titled *Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatalogical Loads* (the "Haldar Report"). The Board stated: *"The Haldar Report raises troubling concerns regarding the as-built design of the LIL with potential significant negative implications for the LIL's reliability."*

[81] For example, during #DarkNL, Newfoundland Power's operations and customer service personnel were mobilized around the clock to complete load rotations, repair system issues that arose due to cold load pick-up, and respond to customer enquiries. Costs associated with this event were approximately $1 million.

[82] For example, the Commission of Inquiry Respecting the Muskrat Falls Project concluded in its report *Muskrat Falls: A Misguided Project*, that *"there is a reasonable likelihood that additional costs will be incurred to ensure that there is adequate reliability for Island ratepayers and, in particular, those who live on the Avalon Peninsula." See Volume 3 – Post-Sanction Events,* March 5, 2020, page 389.

[83] For example, Hydro's *Reliability and Resource Adequacy Study – 2019 Update, Volume III: Long-Term Resource Plan, Page 17, Table 3* estimates the cost of one 58.5 MW simple cycle combustion turbine to be approximately $169 million. Four simple cycle combustion turbines would equate to an additional 234 MW of capacity at a cost of approximately $664 million.

Table 3-14 provides revenue and costs for Newfoundland Power on a ¢ per kWh basis for 2000, 2010 and 2020.

Table 3-14:
Revenue and Costs
2000, 2010, 2020
(¢ per kWh)

	2000	**2010**	**2020**	**Change (2000-2020)**
Revenue	7.65	10.25	12.47	+63%
Purchased Power Costs[84]	4.37	6.62	8.18	+87%
Fixed Costs[85]	1.65	1.99	2.36	+43%
Operating Costs	1.02	0.96	1.12	+10%

Purchased power costs increased by approximately 87% on a ¢ per kWh basis from 2000 to 2020. Fixed costs increased by 43% over the same period. Combined, these costs comprised approximately 85% of revenues on a ¢ per kWh basis in 2020. These costs are largely beyond management's control in any given year.

Operating costs are most directly within management's control. Newfoundland Power's operating costs have been reasonably stable over the last 2 decades. On a ¢ per kWh basis, operating costs increased by approximately 10% over the period 2000 to 2020. When adjusted for inflation, operating costs decreased by approximately 24% over this period.[86] This is reflective of sound cost management.

[84] In 2000, purchased power costs totaled approximately \$199 million. In 2020, these costs increased to approximately \$469 million.

[85] Fixed costs include depreciation, employee future benefits, finance charges and income taxes.

[86] Newfoundland Power's operating costs were approximately 1.47 ¢ per kWh in 2000 when adjusted for inflation. (1.12 – 1.47) / 1.47 = -0.24, or -24%.

Operating costs comprise a smaller proportion of total revenue on a ¢ per kWh basis in 2020 compared to 2000.[87] The reduction of operating costs as a proportion of revenue reduces the Company's flexibility to respond to changes in the business, including lower than forecast sales and higher than expected expenses, such as restoration costs following extreme weather.

Small Size

Newfoundland Power is a relatively small-sized, investor-owned utility. To finance its operations, the Company typically issues long-term first mortgage bonds of $75 million or less. These bond issues typically include 4 investors.[88] The general capital market requirement for inclusion in widely traded bond indices is $100 million and a minimum of 10 investors. Issuances below these thresholds contribute to higher interest rates on long-term debt.

The Board has recognized the relationship between Newfoundland Power's small size and the Company's financial flexibility.[89] The Board previously determined that a strong equity component is needed to mitigate the impact of the Company's relatively small size and low growth potential.[90]

Newfoundland Power's small size relative to its peers continues to define its risk profile.

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87 On a ¢ per kWh basis, operating costs comprised 13% of total revenue in 2000 and 9% of total revenue in 2020.

88 In 2013, the Company issued its $70 million Series AN First Mortgage Bonds to 4 investors. In 2015, the Company issued its $75 million Series AO First Mortgage Bonds to 4 investors. In 2017, the Company issued its $75 million Series AP First Mortgage Bonds to 4 investors. In April 2020, the Company issued its $100 million Series AQ First Mortgage Bonds to 5 investors. Each bond issue was privately placed. The Company's Series AQ First Mortgage Bonds was higher than previous bond issues due to financing requirements associated with redemption of the Company's preference shares in 2020 and uncertainties associated with operating during the COVID-19 pandemic. The Company's next bond issue is currently planned for 2022 and is estimated to be $75 million.

89 See Order No. P.U. 16 (1998-99), page 37.

90 See Order No. P.U. 19 (2003), page 45.

Operating Environment

Newfoundland Power is primarily a distribution utility. The Company currently serves approximately 270,000 customers on the island of Newfoundland. The majority of the Company's customers are residential customers.[91] Approximately 73% of Newfoundland Power's residential customers rely on electricity as their primary heating source.[92]

The Company's electrical system includes approximately 10,750 kilometres of distribution line and 2,100 kilometres of transmission line. Most of this distribution and transmission infrastructure is overhead construction and is exposed to the environment.[93]

The majority of customer outages occur on the distribution system.[94] The leading causes of outages on the distribution system are related to adverse weather conditions, including wind and ice accumulation.[95]

Compared to other electric utilities, Newfoundland Power's service territory is subject to some of the most severe wind and ice conditions for populated regions of Canada.[96] These conditions

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[91] At year-end 2020, the Company had 270,285 customers. Of those, 235,260 were residential (i.e. domestic) customers, 24,195 were general service customers and 10,830 were street and area lighting customers.

[92] Of Newfoundland Power's 235,260 domestic customers, 171,044 used electricity as the primary source of household heating (171,044 / 235,260 = 0.73, or 73%).

[93] Approximately 97% of Newfoundland Power's distribution system and over 99% of the Company's transmission system is overhead construction.

[94] Based on outage duration, approximately 90% of customer outages occurred on the distribution system in 2019. See CEA, *2019 Service Continuity Report – Data*, June 22, 2020.

[95] Based on outage duration, approximately 62% of customer outages on the distribution system were caused by adverse weather in 2019. See CEA, *2019 Service Continuity Report – Data*, June 22, 2020.

[96] The principal design standard for distribution and transmission line design in Canada is the CSA standard *C22.3 No.1-15, Overhead Systems*. This standard recognizes 4 classifications of weather load conditions for ice accumulation, wind loading, and temperature. These are: (i) medium loading B; (ii) medium loading A; (iii) heavy; and (iv) severe. Newfoundland Power's service territory has *heavy* and *severe* loading classifications. Only 2 other provinces throughout Canada are identified as having severe weather loading areas. These are: (i) parts of northern and southern Manitoba; and (ii) rural parts of eastern Quebec, including the Gaspe Peninsula.

have resulted in large-scale customer outages.[97]

Customer outages, particularly during the winter heating season, can present a risk to the health and safety of the population. Newfoundland Power's operational response during periods of customer outages is to mobilize its workforce and restore power on an around-the-clock basis. This can result in unpredictability in costs.[98] Unpredictability in costs can result in volatility in earnings.[99]

Regulatory Mechanisms

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 operates provides for the recovery of prudently incurred costs, including its cost of capital.

[97] Newfoundland Power's service territory experiences significant weather events that cause large-scale customer outages. In March 2010, an ice storm caused extensive damage to 8 of the Company's transmission lines on the Avalon and Bonavista peninsulas. Later that same year, Hurricane Igor caused outages to approximately 77,000 customers and left approximately 100 communities across the island isolated or in states of emergency. A wind storm in 2011 left approximately 41,000 customers without power across the island. In 2012, Tropical Storm Leslie caused damage to Newfoundland Power's electricity system throughout most of Eastern Newfoundland and the Avalon Peninsula. In March 2017, a wind storm with gusts reaching approximately 180 km/h caused widespread outages to approximately 140,000 of the Company's customers. In January 2020, a severe blizzard resulted in over 90 centimeters of snow, primarily on the Avalon Peninsula, wind gusts in excess of 170 km/h and outages to approximately 120,000 customers.

[98] Extreme weather conditions contribute to unscheduled outages on the Company's overhead distribution and transmission infrastructure. As examples: (i) in 2010, an ice storm and Hurricane Igor resulted in costs of approximately $9 million; (ii) in September 2012, Tropical Storm Leslie resulted in costs of approximately $2.5 million; and (iii) in January 2020, a severe blizzard resulted in costs of approximately $1 million.

[99] In its February 2005 report *After the Disaster: Utility Restoration Cost Recovery*, the Edison Electric Institute states: *"Because of the high costs utilities incur in their storm restoration efforts, there is a potential for large financial losses for individual utilities"* (see page 15).

The Board has approved regulatory mechanisms to provide for reasonable recovery of certain costs that are largely beyond management control. These regulatory mechanisms address variability in supply costs, employee future benefits costs and customer program delivery.

Utility supply costs are typically recovered through supply cost mechanisms.[100] The principal supply cost mechanism used by Newfoundland Power is the RSA. The RSA ensures that variations in Hydro's production and marginal energy costs are recovered or rebated in a timely manner. The RSA includes an Energy Supply Cost Variance Clause that addresses variances in purchased power costs resulting from differences between the incremental rate that the Company pays and the average supply cost in customer rates.[101] Other supply cost mechanisms include: (i) a Weather Normalization Reserve that normalizes the effects of weather and hydrology on electricity sales;[102] and (ii) a Demand Management Incentive Account that limits the impacts of variability in demand supply cost.[103]

Employee future benefits are recovered through 2 regulatory mechanisms. The Pension Expense Variance Deferral Account was approved by the Board in 2009.[104] The OPEB Cost Variance Deferral Account was approved by the Board in 2010.[105] These mechanisms address annual fluctuations in pension and OPEB costs that are beyond management control.[106] Such

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[100] A report on the Company's supply cost mechanisms was filed in Newfoundland Power's *2016/2017 General Rate Application (1st Revision), Volume 2, Tab 9.* Supply cost recovery practices for investor-owned distribution utilities in Canada were described in Appendix A to the report.

[101] See Order No. P.U. 43 (2009).

[102] See Order No. P.U. 13 (2013).

[103] See Order No. P.U. 32 (2007).

[104] See Order No. P.U. 43 (2009).

[105] See Order No. P.U. 31 (2010).

[106] This was recognized by the Board in respect of pension costs in Order No. P.U. 43 (2009): Reasons for Decision, page 9, lines 12-13 and 30-32.

mechanisms have been approved in other Canadian jurisdictions to address increased volatility of employee future benefits costs.[107]

Two regulatory mechanisms are designed to provide for the recovery of costs associated with customer program delivery. The CDM Deferral Account was approved by the Board in 2009 and 2013.[108] An Electrification Cost Deferral Account has been proposed for Board approval.[109] These mechanisms are designed to provide for the deferred recovery of costs related to the delivery of customer CDM and electrification programs, which vary annually due to variations in customer participation.

The Board has also approved a mechanism that limits the Company's earnings in any given year. The Excess Earnings Account operates to credit to customers any earnings in excess of the upper limit of the allowed return on rate base as approved by the Board.[110] The sole purpose of the Excess Earnings Account is to protect customer interests by ensuring that Newfoundland Power's earned returns do not materially exceed those approved by the Board for ratemaking purposes. This limits the Company's return on equity to approximately 40-50 basis points above the approved return for ratemaking purposes.[111]

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[107] Employee future benefits cost recovery mechanisms are also in effect for utilities in Ontario, Alberta, and British Columbia.

[108] See Order Nos. P.U. 13 (2009) and P.U. 13 (2013).

[109] See Newfoundland Power's *2021 Electrification, Conservation and Demand Management Application,* filed with the Board on December 16, 2020.

[110] The upper limit on the allowed rate of return on rate base, as established by the Board in Order No. P.U. 19 (2003), is 18 basis points above that used for ratemaking purposes.

[111] Sharing of earnings variances between utilities and customers has been a feature of some, but not all, performance-based ratemaking regimes in Canada. 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 regimes for gas and electric utilities. Alberta's current performance-based regulatory scheme, however, permits utilities to retain all earnings in excess of the allowed return; after utility returns on equity exceed the allowed return by 500 basis points (5%) in a single year or 300 basis points (3%) for 2 consecutive years, the existing scheme may be re-examined.

Overall, the Company's regulatory mechanisms are broadly consistent with current Canadian utility practice.

3.3.3 Impact of Proposed Returns

Exhibit 5 in *Volume 1, Application, Company Evidence and Exhibits* compares Newfoundland Power's forecast financial performance for 2022 and 2023 based on the Company's existing scenario and the proposals contained in this Application.

Table 3-15 provides a summary of Newfoundland Power's regulated returns under the Company's existing scenario and the proposals in this Application.

Table 3-15:
Comparative Rates of Return
Existing and Proposed
2022 and 2023

	2022E	2022P	2023E	2023P
Return on Rate Base (%)	5.90	7.19	5.23	6.97
Return on Equity (%)	7.16	9.80	6.34	9.80

Newfoundland Power's rates of return on rate base for 2022 and 2023, excluding the proposals in this Application, are 5.90% and 5.23%, respectively. This equates to returns on equity of 7.16% for 2022 and 6.34% for 2023.

In this Application, Mr. James Coyne of Concentric Energy Advisors Inc. has provided an expert opinion on the Company's return on equity. Mr. Coyne recommends a fair rate of return on equity for Newfoundland Power of 9.8% based upon a capital structure with a 45% common equity component.[112]

Table 3-16 provides a summary of Newfoundland Power's credit metrics under the Company's existing scenario and the proposals in this Application.[113]

Table 3-16:
Credit Metrics
Existing and Proposed
2022 and 2023

	2022E	2022P	2023E	2023P
Pre-tax Interest Coverage (times)	2.2	2.7	2.0	2.9
Cash Flow Interest Coverage (times)[114]	4.7	4.5	5.0	4.9
Cash Flow Debt Coverage (%)[115]	18.7	17.8	19.2	18.4

With the proposals in this Application, the Company's credit metrics will reflect the stable and consistent financial strength observed by Moody's[116] and DBRS.[117]

112 See *Volume 3, Expert Evidence, Tab 2, Cost of Capital.*

113 Cash flow metrics are lower under the proposed forecast when compared to the existing forecast. This is the result of rebalancing energy sales and power supply costs under proposed customer rates, resulting in no energy supply cost variances beginning March 1, 2022.

114 For comparison purposes, excluding the impact of energy supply cost variances that exist under current customer rates, Newfoundland Power's cash flow interest coverage would be 4.0 times in 2022 and 4.2 times in 2023. For more information, see *Section 3.2.8: Credit Metrics.*

115 For comparison purposes, excluding the impact of energy supply cost variances that exist under current customer rates, the Company's cash flow debt coverage would be 15.2% in 2022 and 15.5% in 2023. For more information, see *Section 3.2.8: Credit Metrics.*

116 In its November 16, 2020 Credit Opinion, filed in Exhibit 4 to this Application, Moody's states: *"The stable outlook reflects the PUB's regulation of NPI which we consider credit supportive. We expect the regulatory environment to remain supportive, with the company maintaining a suite of timely recovery mechanisms, along with our view that relatively stable cash flow generation and the capital structure of NPI will generate sustained CFO pre-WC to debt in the 16-18% range"* (page 2).

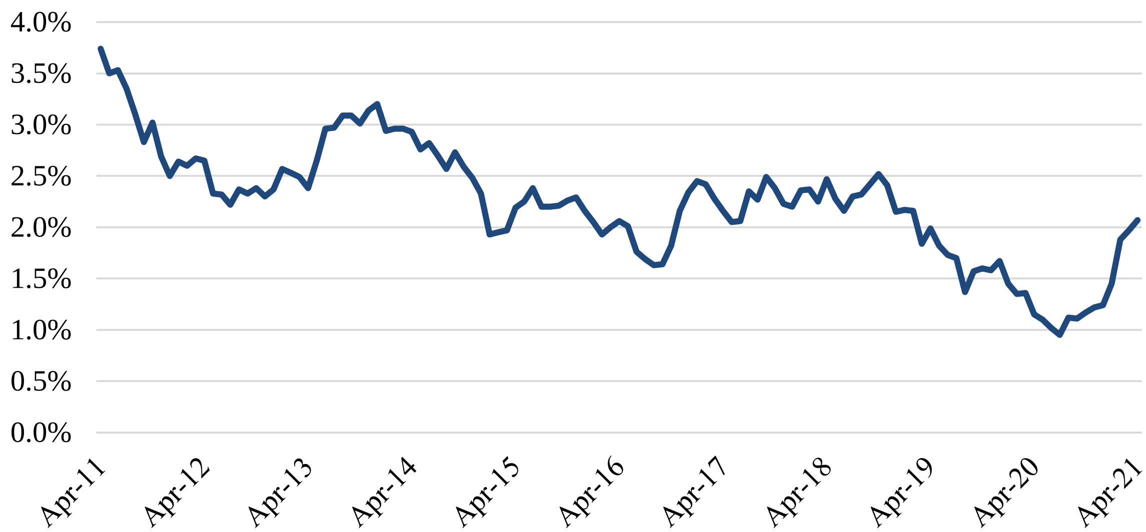
117 In its October 19, 2020 Rating Report, filed in Exhibit 4 to this Application, DBRS states: *"Newfoundland Power has maintained a solid financial profile, underpinned by the Company's reasonable financial leverage and stable cash flows. For the LTM ended June 30, 2020, Newfoundland Power's total debt in the capital structure remained low at approximately 56.1%, while its cash flow-to-debt and EBIT interest coverage ratios remained solid at 18.1% and 2.38 times, respectively"* (page 3).

3.3.4 Automatic Adjustment Formula

The Board adopted the Automatic Adjustment Formula (the "Formula") in 1998 to determine changes to the Company's return on equity between rate applications.[118] The Formula was designed to adjust Newfoundland Power's return on equity based on forecast changes in long Canada bond yields, which serve as a proxy for the risk free rate.

Figure 3-5 shows long Canada bond yields for the period April 2011 to April 2021.

Figure 3-5:
30-Year Canada Bond Yields[119]
(April 2011 to April 2021)



The Board suspended use of the Formula in April 2013 following Newfoundland Power's *2013/2014 General Rate Application*. The average long Canada bond yield for April 2013 was 2.38%.

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118 Cost of capital formulas to determine return on equity for ratemaking purposes in Canada originated with the British Columbia Utilities Commission decision to adopt a formula in 1994. Following this, the National Energy Board and the Manitoba Public Utilities Board each adopted formulas to estimate the cost of equity for 1995. The predecessor to the Alberta Utilities Commission, the Ontario Energy Board, and the Régie de l'énergie also adopted formulas over the period 1997 to 2004. The Board approved use of the Formula for Newfoundland Power in Order No. P.U. 16 (1998-99).

119 See https://www.bankofcanada.ca/rates/interest-rates/lookup-bond-yields/.

In its final order, the Board stated:

> *"While the Board continues to see the value of an automatic adjustment formula, 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."*[120]

Newfoundland Power's *2019/2020 General Rate Application* was filed in June 2018. The average long Canada bond yield during that month was 2.16%. Continued suspension of the Formula formed part of the settlement agreement reached as part of that application. Suspension of the Formula was subsequently approved by the Board until Newfoundland Power's next general rate application.[121]

During April 2021, the average long Canada bond yield was 2.07%. This is comparable to the abnormally low long Canada bond yields observed when the Formula was suspended in 2013, 2016 and 2019.

Given there has been no appreciable change in the long Canada bond yields, Newfoundland Power proposes the continued suspension of the Formula in determining the Company's rate of

[120] See Order No. P.U. 13 (2013), page 36, lines 38-44.
[121] See Order No. P.U. 2 (2019), page 15, lines 13-24.

return on equity between test years. This is consistent with current Canadian regulatory practice.[122]

3.4 REGULATORY ACCOUNTING MATTERS

The Application includes a review of Newfoundland Power's General Expenses Capitalized. The review determined that the Company's methodology for calculating General Expenses Capitalized is consistent with established regulatory principles and sound public utility practice.

The Application proposes minor changes to the calculation of General Expenses Capitalized to account for changes in Newfoundland Power's operations since the matter was last considered by the Board. These revisions are proposed to be effective January 1, 2023 and would decrease the 2023 revenue requirement by approximately $0.1 million.

The Application proposes to remove pension costs from General Expenses Capitalized and to capitalize pension costs by way of a labour loader. The capitalization of pension costs by way of a labour loader is consistent with sound public utility practice. The proposed change in the treatment of pension costs will increase the 2023 revenue requirement by approximately $1.4 million, primarily due to income tax effects.

[122] The National Energy Board, Manitoba Public Utilities Board, Alberta Utilities Commission, and the Régie de l'énergie have discontinued the use of automatic adjustment formulas. In 2013, the British Columbia Utilities Commission ("BCUC") reinstated use of an Automatic Adjustment Mechanism ("AAM") to adjust rates of return on equity for utilities within British Columbia. However, the AAM requires that long Canada bond yields reach a threshold of 3.8% before the mechanism will operate. Since the inception of the AAM, long Canada bond yields have remained below 3.8%, and the AAM has never operated (see BCUC Decision L-543-13). Unlike most regulators, the Ontario Energy Board ("OEB") did not abandon the use of a formulaic basis of determining rate of return on equity for utilities in Ontario. In 2009, the OEB concluded that this approach was necessary to be able to continue regulatory oversight of over 80 utilities in Ontario (see OEB Staff Report, EB-2009-0084, *Review of the Cost of Capital for Ontario's Regulated Utilities*, January 14, 2016).

The Application proposes to increase the amortization period for CDM program costs from 7 years to 10 years, and to amortize electrification program costs over 10 years. The amortization of program costs over 10 years is consistent with sound public utility practice.

3.4.1 General Expenses Capitalized Review

General

In February 2021, the Board requested that Newfoundland Power include a review of its General Expenses Capitalized ("GEC") methodology and calculation with its next general rate application. The Board requested that the review address why the Company includes pension costs in its GEC calculation and the impact on revenue requirement and customer rates if pension costs were directly charged to capital projects by way of a labour loader.[123]

The Company's review of GEC (the "GEC Review") is provided in *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized.*

Review of GEC Methodology

Newfoundland Power has followed the incremental cost method to allocate general expenses to GEC since 1999.[124] Under the incremental cost method, only general expenses that are incremental to the utility as a result of its capital program may be capitalized.[125]

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[123] See correspondence from the Board to Newfoundland Power, dated February 16, 2021.

[124] In Order No. P.U. 3 (1995-96), the Board approved Newfoundland Power's proposal to change from the full cost method to the incremental cost method to allocate general expenses to GEC. The Board ordered that the new GEC methodology be phased in over the 5-year period from 1995 to 1999.

[125] Under the full cost method, any general expense incurred in connection with the capital program may be capitalized, regardless of whether they would be fully eliminated if there was no capital program.

The GEC Review found that use of the incremental cost method continues to be reasonable from 3 perspectives.

First, the incremental cost method results in relatively stable allocations to GEC.[126] This is consistent with the regulatory principle of customer rate stability.

Second, the incremental cost method limits the allocation of general expenses to GEC to only those expenses that are necessary to bring an asset into service, and recovers those costs over the life of the asset. This is consistent with the regulatory principle of intergenerational equity.[127]

Third, Newfoundland Power's use of the incremental cost method has provided for overall capitalization amounts that are reasonably consistent with other Canadian utilities.[128]

Review of the GEC Calculation

The GEC Review confirmed that all general expenses included in the GEC calculation remain appropriate, with the exception of those related to printing services.[129]

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126 For example, over the last 20 years, annual GEC amounts ranged from $2.1 million to $3.1 million, or 2.6% to 5.0% of total capital expenditures. Over the 5-year period 1991 to 1995, when the Company applied the full cost method, annual GEC amounts ranged from $8.3 million to $11.5 million, or 23% to 31% of total capital expenditures.

127 According to the principle of intergenerational equity, customers should bear only those costs that are required to provide them with service in a given period.

128 See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Attachment 1, Appendix E, Survey of Capitalization Practices of Canadian Utilities*, Page E-3, Question 7. Expressed as a percentage, overhead construction costs averaged 10% among survey respondents in relation to the utilities' total capital expenditures in 2019. This compares to 9% for Newfoundland Power (adjusted to remove the impact of pension costs).

129 Printing services primarily relate to customer service requirements, such as printing customer bills. Historically, printing services would also include printing forms and service orders related to capital jobs. Printing volumes associated with capital related forms and orders are currently low with the digitization of forms in recent years. As a result, the reduction in printing services would be immaterial if the capital program was eliminated. Approximately $37,000 of printing services expenses were allocated to GEC in 2020.

The GEC Review indicated that general expenses related to information systems should be added to the GEC calculation. Similar to other general office activities, there would be lower work requirements associated with information systems if there was no capital program.[130]

All general expenses proposed to be included in the GEC calculation are consistent with the definition of Capitalized Overheads in the Federal Energy Regulatory Commission ("FERC") System of Accounts, reflecting sound public utility practice.[131]

The GEC Review considered the ratios applied in allocating amounts to GEC. Certain changes to existing GEC ratios are proposed to account for changes in Newfoundland Power's operations since the matter was last considered by the Board in 1999.

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[130] These tasks primarily relate to planning information systems related solutions, including software enhancements and system upgrades. There would also be lower work requirements associated with providing technical support reflecting a reduction in employees and personal computers.

[131] Section 4 of the *FERC Uniform System of Accounts – Electric Plant Instructions* provides for the capitalization of all overhead construction costs, such as engineering, supervision and general office salaries and expenses.

Table 3-17 summarizes the existing and revised GEC ratios.

Table 3-17:
GEC Ratios: Existing vs. Revised

General Expense	**Existing Ratios**	**Revised Ratios**
<u>Construction Activities</u>		
Capital Planning	Direct	Direct
Operating Supervision	15%	15%
Tools, Equipment and Safety Clothing	48%	65%
System Operations	Direct	10%
<u>Non-Construction Activities</u>		
Finance	13%	10%
Human Resources	13%	10%
Information Systems	-	10%
Employee Welfare[132]	31%	-
Printing Services[133]	13%	-

The existing ratios for capital planning[134] and operating supervision[135] continue to reasonably reflect the reduction in costs that would occur if there was no capital program.

The existing ratio of 48% for tools, equipment and safety clothing is proposed to be adjusted to 65% to reflect the Company's current regional labour allocation related to capital work.[136]

The ratio for system operations is proposed to be adjusted to 10%. This reflects an estimated reduction in labour requirements for system operations if there was no capital program.[137]

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132 Employee welfare expenses are proposed to be grouped with human resources expenses. See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix B, Section 3.3.*

133 Printing services are proposed to be removed from the GEC calculation. See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix A.*

134 See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix B, Section 2.1.*

135 See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix B, Section 2.2.*

136 See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix B, Section 2.3.*

137 See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix B, Section 2.4.*

The ratios for non-construction activities, including finance, human resources and information systems, are proposed to be adjusted to reflect a rate of 10%. Given the nature of these departments, it is difficult to estimate the reduction in general expenses that would occur if there was no capital program.[138] The Board has previously indicated that the use of a nominal rate of 10% is a reasonable proxy in these circumstances.[139]

Table 3-18 provides a *pro forma* analysis of the existing and revised ratios based on 2020 general expenses.

Table 3-18:
GEC Calculation
***Pro Forma* 2020**
($000s)

	2020 *Pro Forma*	**2020 Actual**
Construction activities	2,695	2,706
Non-construction activities	756	641
Total GEC	**3,451**	**3,347**

Using the revised ratios, *pro forma* 2020 GEC is approximately $3,451,000. This is reasonably consistent with the actual GEC amount calculated for 2020 of $3,347,000.

Given the comparability of these amounts, the revised GEC ratios will continue to provide overall capitalization amounts that are consistent with other Canadian electric utilities.

[138] See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix B, Section 3.0.*
[139] See Order No. P.U. 3 (1995-1996), page 19.

These revisions to the GEC calculation are proposed to be effective January 1, 2023 and would decrease the 2023 revenue requirement by approximately $0.1 million.

Allocation of Pension Costs

The Application proposes to remove pension costs from the Company's GEC calculation and directly charge pension costs to capital projects by way of a labour loader, effective January 1, 2023.

Allocating pension costs directly to capital projects by way of a labour loader is consistent with sound public utility practice and the Company's current treatment of OPEB costs.[140]

This change in the treatment of pension costs will increase the 2023 revenue requirement by approximately $1.4 million. This is the result of income tax timing effects.[141] The estimated impact on customer rates is an increase of approximately 0.2%.

The income tax effects associated with the proposed change in the allocation of pension costs will reverse over time, resulting in a decrease in revenue requirements in subsequent years.[142] Ultimately, there would be no impact on the total revenue requirement recovered through customer rates over service lives of the related capital assets.

[140] Ten of 11 survey respondents capitalize pension costs by means of a labour loader. See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Attachment 1, Appendix E,* Page E-3, Question 5a.

[141] For a discussion of these income tax effects, see *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Section 4.2 Revenue Requirement Effects.*

[142] See *Volume 2, Supporting Materials, Tab 6, Review of General Expenses Capitalized, Appendix D,* which illustrates the income tax timing differences over the lives of the related capital assets resulting from allocating pension costs via GEC versus directly charging pension costs using a labour loader.

3.4.2 Customer Program Costs

General

In Order No. P.U. 13 (2013), the Board approved the CDM Cost Deferral Account and the amortization of CDM program costs over 7 years. The 7-year amortization period was determined to be consistent with sound public utility practice at that time.[143]

In 2020, Newfoundland Power proposed the approval of an Electrification Cost Deferral Account.[144] The application indicated that the amortization period for electrification program costs would be determined as part of the Company's next general rate application.

Exhibits 12 and 13 in *Volume 1, Application, Company Evidence and Exhibits* provide the definitions of the CDM Cost Deferral Account and Electrification Cost Deferral Account, respectively.

CDM and electrification programs provide cumulative and enduring benefits for customers.[145] Newfoundland Power reviewed current public utility practice with respect to the recovery of CDM and electrification program costs to determine reasonable amortization periods for program costs.

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[143] Public utility practice in 2012 indicated the recovery of CDM program costs over periods of 5 to 15 years. See Newfoundland Power's *2013/2014 General Rate Application, Volume 1, Section 3.4.3 Conservation Program Costs.*

[144] See Newfoundland Power's *2021 Electrification, Conservation and Demand Management Application,* filed with the Board on December 16, 2020.

[145] See *Volume 1, Application, Company Evidence and Exhibits, Section 2.2.4 Customer Conservation and Electrification.*

Recovery of CDM Program Costs

Current public utility practice indicates the recovery of CDM program costs over 10 years.[146] This amortization period generally corresponds with the average useful life of the technologies captured by utilities' CDM programs.[147]

Newfoundland Power is proposing to increase the amortization period for its customer CDM programs from 7 to 10 years. An amortization period of 10 years for CDM programs is consistent with current public utility practice and the average life of the technologies captured by the Company's CDM programs.[148]

The amortization of CDM program costs over 10 years is proposed to be effective for program costs incurred commencing January 1, 2021. CDM program costs incurred in prior years would continue to be amortized over 7 years in accordance with Order No. P.U. 13 (2013).

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146 Manitoba Hydro, FortisBC and Hydro Quebec amortize CDM program costs over a 10-year period.

147 BC Hydro amortizes CDM program costs over a 15-year period. This timeframe corresponds to the average life of the technologies in BC Hydro's portfolio.

148 The average life of the technologies in Newfoundland Power's portfolio of CDM programs is determined based on the forecast Weighted Persistence of Energy Savings over the period 2021 to 2025. The Weighted Persistence of Energy Savings measures the period over which benefits are provided to customers through CDM programs. Results are weighted based upon the percentage of total energy savings attributable to each program. The Weighted Persistence of Energy Savings is 10.6 years for Newfoundland Power's customer CDM programs.

Table 3-19 provides the *pro forma* impacts of amortizing customer CDM programs over 7 and 10 years from 2021F to 2025F.

Table 3-19:
CDM Program Costs
***Pro forma* Forecast Deferral and Amortizations**
2021F to 2025F
($000s)

	2021F	2022F	2023F	2024F	2025F
7-Year Amortization Period					
Deferral	(6,530)	(7,170)	(7,006)	(6,305)	(6,560)
Forecast Amortization[149]	-	933	1,957	2,958	3,859
Historical Amortization[150]	5,890	5,256	4,596	3,568	2,603
Total Amortization	**5,890**	**6,189**	**6,553**	**6,526**	**6,462**
10-Year Amortization Period					
Deferral	(6,530)	(7,170)	(7,006)	(6,305)	(6,560)
Forecast Amortization	-	653	1,370	2,071	2,701
Historical Amortization	5,890	5,256	4,596	3,568	2,603
Total Amortization	**5,890**	**5,909**	**5,966**	**5,639**	**5,304**
Difference in Total Amortization	**-**	**(280)**	**(587)**	**(887)**	**(1,158)**

Increasing the amortization period for CDM programs from 7 years to 10 years would reduce revenue requirements in 2022 and 2023 by approximately $280,000 and $587,000, respectively.

[149] Forecast amortizations reflect program costs incurred over the period 2021 to 2025.
[150] Historical amortizations reflect program costs incurred prior to 2021.

Recovery of Electrification Program Costs

Current public utility practice indicates the recovery of electrification program costs over periods of 5 to 15 years. Costs for pilot programs and electric vehicle rebates are generally recovered over periods of 5 to 10 years.[151] Costs for electric vehicle infrastructure are generally recovered over periods of 10 to 15 years.[152]

Newfoundland Power is proposing to amortize customer electrification programs over 10 years. An amortization period of 10 years for electrification programs is consistent with sound public utility practice and the average life of the technologies in the Company's portfolio of electrification programs.[153]

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[151] Consumers Energy in Michigan recovers electrification pilot program costs over 5 years. Xcel Energy in Colorado recovers electrification program costs over 10 years. Electric vehicle program costs in Maryland are recovered over 5 years.

[152] Utilities in New York recover costs for make-ready charging infrastructure for electric vehicles over 15 years. Rebates for electric vehicle chargers are recovered over 10 years in New Mexico and Oregon.

[153] The average life of the technologies in Newfoundland Power's portfolio of electrification programs is determined based on the forecast Weighted Persistence of Energy Usage over the period 2021 to 2025. The Weighted Persistence of Energy Usage measures the period over which benefits are accrued for customers through electrification programs. Results are weighted based upon the percentage of total energy usage attributable to each program. The Weighted Persistence of Energy Usage is 9.6 years for Newfoundland Power's customer electrification programs.

Table 3-20 provides the *pro forma* impacts of amortizing customer electrification programs over 10 years from 2021F to 2025F.

Table 3-20:
Electrification Program Costs
***Pro forma* Forecast Deferral and Amortizations**
2021F to 2025F
($000s)

	2021F	**2022F**	**2023F**	**2024F**	**2025F**
10-Year Amortization Period					
Deferral	(1,336)	(3,014)	(3,944)	(4,494)	(4,385)
Forecast Amortization	-	134	435	829	1,279

Annual amortizations are forecast to increase over time. This dynamic of increasing recovery is consistent with the amortization of CDM program costs. Increasing recovery is reasonable given the cumulative nature of the benefits of these programs.

Exhibit 14 in *Volume 1, Application, Company Evidence and Exhibits* provides the proposed revisions to the Rate Stabilization Clause to reflect the amortization of CDM program costs and electrification program costs over 10 years.

3.5 REGULATORY AMORTIZATIONS

3.5.1 Overview

Table 3-21 summarizes the amortization of regulatory deferrals approved by the Board and the amortization of regulatory deferrals proposed in this Application.

Table 3-21:
Amortization of Regulatory Deferrals
***Pro forma* Revenue Requirement Impact**
2019 to 2023P
($000s)

	2019	2020	2021F	2022P	2023P
2019 Hearing Costs Deferral[154]	294	353	353	-	-
2019 Revenue Surplus[155]	1,752	(876)	(876)	-	-
2022 Hearing Costs Deferral[156]	-	-	-	294	353
2022 Revenue Shortfall[157]	-	-	-	(892)	444
Revenue Requirement Impact	**2,046**	**(523)**	**(523)**	**(598)**	**797**

[154] In Order No. P.U. 2 (2019), the Board approved the amortization of Newfoundland Power's *2019/2020 General Rate Application* hearing costs in an amount up to $1.0 million for the 34-month period commencing on March 1, 2019 and ending December 31, 2021.

[155] In Order No. P.U. 2 (2019), the Board approved the amortization of a revenue surplus of $2,482,000 related to the March 1, 2019 rate implementation date over a 34-month period commencing on March 1, 2019 and ending December 31, 2021. This represents approximately $73,000 per month. For 2019, it represents amortization over 10 months, or approximately $730,000 ($2,482,000 - $730,000 = $1,752,000). For 2020 and 2021, this represents approximately $876,000 per year.

[156] The amortization of $1.0 million related to Newfoundland Power's *2022/2023 General Rate Application* hearing costs is proposed in this Application. See *Section 3.5.2: Hearing Costs.*

[157] The amortization of a 2022 revenue shortfall of $1,262,000 related to the March 1, 2022 rate implementation date is proposed in this Application over a 34-month period commencing March 1, 2022 and ending December 31, 2024. This represents approximately $37,000 per month. For 2022, it represents amortization over 10 months, or approximately $370,000 ($1,262,000 - $370,000 = $892,000). For 2023 and 2024, this represents approximately $444,000 per year. See *Section 3.5.3: 2022 Revenue Shortfall.*

3.5.2 Hearing Costs

Newfoundland Power estimates that $1.0 million in costs will be incurred and billed to the Company by the Board and Consumer Advocate as a result of the *2022/2023 General Rate Application*. Consistent with previous Board practice, Newfoundland Power proposes to recover these costs in customer rates over a 34-month period commencing on March 1, 2022 and ending December 31, 2024.[158] The Company also proposes that any difference between actual and estimated Board and Consumer Advocate costs for rate setting purposes be rebated or recovered through the RSA.[159]

3.5.3 2022 Revenue Shortfall

Implementation of customer rates beginning on March 1, 2022 based on the proposed 2023 revenue requirement would result in a $1,262,000 shortfall in recovering the proposed 2022 revenue requirement. Newfoundland Power is proposing to amortize this amount over a 34-month period commencing on March 1, 2022 and ending December 31, 2024. The proposed treatment of the 2022 revenue shortfall is consistent with past practice of the Board.[160]

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158 In the past, the Board has ordered recovery of Application costs over a 3-year period on a number of occasions. See Order Nos. P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), P.U. 13 (2013), P.U. 18 (2016) and P.U. 2 (2019).

159 Recovery of an estimate of $1.0 million in Board and Consumer Advocate costs formed part of the settlement agreement related to Newfoundland Power's *2019/2020 General Rate Application* with any difference between actual cost and estimated costs to be rebated or collected through the RSA. The settlement agreement was approved in Order No. P.U. 2 (2019).

160 In Order No. P.U. 13 (2013), the Board approved recovery of a forecast revenue shortfall of an estimated $980,000 resulting from the implementation of new rates after January 1, 2013. In Order No. P.U. 18 (2016), the Board approved recovery of a forecast revenue shortfall of an estimated $1,410,000 resulting from the implementation of new rates after January 1, 2016. In Order No. P.U. 25 (2016), the Board approved final customer rates resulting from the Company's *2016/2017 General Rate Application*. This included the amortization of a revenue surplus for 2016 resulting from the July 1, 2016 implementation. In Order No. P.U. 2 (2019), the Board approved final customer rates resulting from the Company's *2019/2020 General Rate Application*. This included the amortization of a revenue surplus for 2019 resulting from the March 1, 2019 implementation.

SECTION 4: RATE BASE AND REVENUE REQUIREMENT

4.1 OVERVIEW

This section of evidence addresses the Company's forecast 2022 and 2023 average rate base and revenue requirements.

Based on the Company's proposals in this Application, the forecast 2022 and 2023 average rate base is approximately $1,240 million and $1,289 million, respectively.

Based on the Company's proposals in this Application, the forecast 2022 and 2023 revenue requirements are approximately $715 million and $713 million, respectively.

To generate the revenue necessary to meet the Company's forecast revenue requirements in 2022 and 2023, an average increase in existing customer rates of approximately 0.8%, effective March 1, 2022, will be required.

4.2 2022 AND 2023 RATE BASE

Exhibit 6 in *Volume 1, Application, Company Evidence and Exhibits*, provides Newfoundland Power's forecast 2022 and 2023 average rate base.

Newfoundland Power's forecast 2022 and 2023 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] See *Volume 2, Supporting Materials, Tab 2, 2022 and 2023 Rate Base Allowances.*

The Company's forecast 2022 and 2023 average rate base is approximately $1,240 million and $1,289 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] Forecast 2022 and 2023 average rate base include the Company's forecast capital expenditures and is calculated in accordance with established practice and Board orders.[4]

4.3 2022 AND 2023 REVENUE REQUIREMENTS

4.3.1 Summary of Revenue Requirements

Exhibit 7 in *Volume 1, Application, Company Evidence and Exhibits*, provides Newfoundland Power's 2022 and 2023 forecast revenue requirements.[5]

The Company's revenue requirement is forecast to be approximately $715 million in 2022 and $713 million in 2023.

[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 *2022 Capital Budget Application* filed on May 18, 2021.

[3] Annual depreciation expense is currently calculated using the composite depreciation rates approved by the Board in Order No. P.U. 18 (2016). The Company is proposing composite depreciation rates based on the *2019 Depreciation Study*, found in *Volume 3, Expert Evidence, Tab 1.* See *Volume 1, Application, Company Evidence and Exhibits, Section 3.2.3: Depreciation.*

[4] The forecast capital expenditures for 2022 and 2023 are described in the *2022 Capital Budget Application*.

[5] Exhibit 9 in *Volume 1, Application, Company Evidence and Exhibits*, displays the 2022 and 2023 revenue requirements in the absence of the proposals contained in this Application.

Table 4-1 provides a summary of Newfoundland Power's forecast 2022 and 2023 revenue requirements and the revenue required to be recovered from customer rates.

Table 4-1:
Summary of Revenue Requirements
2022F and 2023F
($000s)

	2022F	**2023F**
Power Supply Cost	464,811	459,924
Operating Costs[6]	67,495	73,226
Employee Future Benefit Costs	8,745	2,771
Deferred Cost Recoveries and Amortizations	(892)	444
Depreciation	70,956	75,252
Income Taxes[6]	22,154	24,198
Return on Rate Base	89,173	89,844
Revenue Requirement	**722,442**	**725,659**
Adjustments		
Other Revenue	(5,924)	(6,473)
Interest on Security Deposits	18	18
Energy Supply Cost Variance Adjustments	4,871	-
CDM Program Amortization	(5,909)	(5,966)
Electrification Program Amortization	(134)	(435)
Revenue Requirement from Rates	**715,364**	**712,803**

[6] For revenue requirement purposes, operating costs and income taxes do not include non-regulated expenses.

4.3.2 Costs and Depreciation

Table 4-2 provides forecast 2022 and 2023 power supply costs.

Table 4-2:
Power Supply Costs
2022F and 2023F
($000s)

	2022F	**2023F**
Existing	465,610	461,686
Elasticity Impact	(799)	(1,762)
Proposed	**464,811**	**459,924**

Table 4-3 provides forecast 2022 and 2023 operating costs.[7]

Table 4-3:
Operating Costs
2022F and 2023F
($000s)

	2022F	**2023F**
Existing	67,347[8]	69,736[9]
2022 Hearing Costs[10]	294	353
CDM Program Amortization[11]	(280)	(587)
Electrification Program Amortization[12]	134	435
Changes in GEC[13]	-	3,289
Proposed	**67,495**	**73,226**

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7 Exhibits 1 and 2 in *Volume 1, Application, Company Evidence and Exhibits*, provide the forecast gross operating costs for 2022 and 2023. These are reviewed in detail in *Volume 1, Application, Company Evidence and Exhibits, Section 2.4*: *Operating and Capital Costs.*

8 Existing operating costs in 2022 include: (i) gross operating costs of approximately $66.5 million (see Exhibits 1 and 2); (ii) plus amortization of CDM costs of $6.2 million, as approved by the Board in Order No. P.U. 13 (2013); (iii) less GEC of approximately $5.4 million.

9 Existing operating costs in 2023 include: (i) gross operating costs of approximately $68.6 million (see Exhibits 1 and 2); (ii) plus amortization of CDM costs of $6.5 million as approved by the Board in Order No. P.U. 13 (2013); (iii) less GEC of approximately $5.4 million.

10 See *Volume 1, Application, Company Evidence and Exhibits, Section 3.5.2: Hearing Costs*.

11 See *Volume 1, Application, Company Evidence and Exhibits, Section 3.4.2: Customer Program Costs*.

12 See *Volume 1, Application, Company Evidence and Exhibits, Section 3.4.2: Customer Program Costs*.

13 See *Volume 1, Application, Company Evidence and Exhibits, Section 3.4.1: General Expenses Capitalized Review*. The increase in operating costs related to the *General Expenses Capitalized Review* primarily relates to the proposed change in pension capitalization of $3,388,000, which is offset by a decrease in employee future benefit costs of $3,388,000. See *Table 4-4: Employee Future Benefits Costs*. The remaining ($99,000) relates to the proposed changes to the GEC calculation ($3,289,000 - $3,388,000 = -$99,000).

1 Table 4-4 provides forecast 2022 and 2023 employee future benefits costs.

Table 4-4:
Employee Future Benefits Costs
2022F and 2023F
($000s)

	2022F	**2023F**
Pension Expense[14]	912	(1,780)
OPEB Expense[15]	7,833	7,939
Existing	**8,745**	**6,159**
Changes to GEC[16]	-	(3,388)
Proposed	**8,745**	**2,771**

2 Table 4-5 provides forecast 2022 and 2023 deferred cost recoveries and amortizations.

Table 4-5:
Deferred Cost Recoveries and Amortizations
2022F and 2023F
($000s)

	2022F	**2023F**
2022 Revenue Shortfall[17]	(892)	444
Proposed	**(892)**	**444**

[14] See *Volume 1, Application, Company Evidence and Exhibits, Section 3.2.4: Employee Future Benefits, Pensions*.

[15] See *Volume 1, Application, Company Evidence and Exhibits, Section 3.2.4: Employee Future Benefits, OPEB*.

[16] See *Volume 1, Application, Company Evidence and Exhibits, Section 3.4.1: General Expenses Capitalized Review*. The decrease in employee future benefit costs is offset by an increase in operating costs. See footnote 13.

[17] The 2022 revenue shortfall of approximately $1.3 million related to the March 1, 2022 rate implementation date is proposed to be amortized evenly over a 34-month period from March 1, 2022 to December 31, 2024. See *Volume 1, Application, Company Evidence and Exhibits, Section 3.5.3: 2022 Revenue Shortfall.*

1 Table 4-6 provides forecast 2022 and 2023 depreciation costs.

Table 4-6:
Depreciation Costs
2022F and 2023F
($000s)

	2022F	2023F
Existing[18]	70,424	74,745
2019 Depreciation Study	532	507
Proposed	**70,956**	**75,252**

2 Table 4-7 provides forecast 2022 and 2023 income taxes.

Table 4-7:
Income Taxes
2022F and 2023F
($000s)

	2022F	2023F
Existing[19]	15,384	13,294
Tax Effects of Application Proposals[20]	6,770	10,904
Proposed[21]	**22,154**	**24,198**

[18] The Company is proposing to implement the depreciation rates from the *2019 Depreciation Study* effective January 1, 2022, and to amortize the accumulated reserve variance of $31.9 million over the average remaining service life of the affected asset classes. See *Volume 1, Application, Company Evidence and Exhibits, Section 3.2.3 Depreciation*.

[19] See Exhibit 5 in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 22.

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

	($000s)	
	2022F	2023F
Increase in Forecast Revenue Requirement from Rates, Exhibit 7, line 22	3,802	4,405
Change in Transfers to the RSA, Exhibit 7, lines 17 and 19	18,500	28,436
Increase in Taxable Revenue	22,302	32,841
Change in Tax Deductible Expenses (i.e. power supply, operating and finance charges)	(2,142)	(1,166)
Increase in Taxable Income	20,160	31,675
Tax Rate	30.0%	30.0%
Change in Cash Income Taxes	6,048	9,503
Change in Deferred Income Taxes	722	1,401
Change in Total Income Taxes	**6,770**	**10,904**

[21] See Exhibit 5 in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 22.

4.3.3 Return on Rate Base

Exhibit 8 in *Volume 1, Application, Company Evidence and Exhibits*, provides Newfoundland Power's proposed 2022 and 2023 return on rate base.

Table 4-8 summarizes the proposed 2022 and 2023 return on rate base and rate of return on rate base.

Table 4-8:
Return on Rate Base
2022F and 2023F
($000s)

	2022F	**2023F**
Forecast Average Rate Base	1,239,558[22]	1,289,405[23]
Forecast Regulated Returns		
Debt	34,694	33,056
Common Equity	54,479	56,788
Return on Rate Base	**89,173**	**89,844**
Rate of Return on Rate Base (%)	**7.19**[24]	**6.97**[25]

[22] The 2022F average rate base is shown in Exhibit 6 in *Volume 1, Application, Company Evidence and Exhibits*.
[23] The 2023F average rate base is shown in Exhibit 6 in *Volume 1, Application, Company Evidence and Exhibits.*
[24] The forecast rate of return on rate base for 2022 is calculated as ($89,173 / $1,239,558 = 7.19%), as shown in Exhibit 8 in *Volume 1, Application, Company Evidence and Exhibits.*
[25] The forecast rate of return on rate base for 2023 is calculated as ($89,844 / $1,289,405 = 6.97%), as shown in Exhibit 8 in *Volume 1, Application, Company Evidence and Exhibits.*

4.3.4 Deductions from Revenue Requirement

Table 4-9 provides the forecast 2022 and 2023 deductions from revenue requirement.

Table 4-9:
Deductions from Revenue Requirement
2022F and 2023F
($000s)

	2022F	**2023F**
Other Revenue	(5,924)[26]	(6,473)[27]
Transfers to the RSA	(1,172)[28]	(6,401)[29]
Interest on Security Deposits[30]	18	18
Proposed	**(7,078)**	**(12,856)**

[26] See Exhibit 5 in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 11.
[27] See Exhibit 5 in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 11.
[28] The 2022 transfers to the RSA reflect a -$4,871,000 balance in the Energy Supply Cost Variance Reserve at March 1, 2022, $5,909,000 related to the amortization of CDM program costs and $134,000 related to the amortization of proposed customer electrification program costs.
[29] The 2023 transfers to the RSA reflect $5,966,000 related to the amortization of CDM program costs and $435,000 related to the amortization of proposed customer electrification program costs.
[30] Interest on customer security deposits is not included in the determination of revenue requirements.

4.3.5 Required Revenue Increase

Table 4-10 provides a forecast increase in revenue from rates of approximately $4.3 million required to meet the Company's proposed 2022 revenue requirement and approximately $5.5 million required to meet the Company's proposed 2023 revenue requirement.[31]

Table 4-10:
Required Revenue Increases
2022F and 2023F
($000s)

	2022F	2023F
Proposed Revenue From Rates	**715,364**	**712,803**
Revenue From Existing Rates	(711,562)	(708,398)
Elasticity Impacts[32]	479	1,075
Required Increase in Revenue from Rates	**4,281**	**5,480**

The required increase in revenue from rates translates into a customer rate increase of 0.8% effective March 1, 2022.[33]

[31] See Exhibit 9 in *Volume 1, Application, Company Evidence and Exhibits*, Column E.
[32] See Exhibit 9 in *Volume 1, Application, Company Evidence and Exhibits*, Column D.
[33] See Exhibit 10 in *Volume 1, Application, Company Evidence and Exhibits*, Column F.

SECTION 5: CUSTOMER RATES

5.1 OVERVIEW

The number of customers served by Newfoundland Power is forecast to increase by 0.4% in each of 2021 and 2022 and by 0.3% in 2023. Energy sales are forecast to decrease by 0.2% in 2021, 0.4% in 2022, and 0.7% in 2023. Demand is forecast to increase by 3.9% in 2021, remain steady in 2022, and decrease by 0.7% in 2023.

In this Application, the Company seeks an average increase in customer rates of 0.8%, effective March 1, 2022. It is proposed that the average increase be applied to each rate class.

5.2 CUSTOMER, ENERGY AND DEMAND FORECAST

5.2.1 Customers Served

Newfoundland Power is the primary distributor of electricity on the Island Interconnected System and is responsible for retail pricing for the approximately 294,400 customers served by the system.[1]

[1] Hydro serves approximately 24,000 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.

Table 5-1 shows the forecast percentage of total customers and energy sales by rate class for the 2023 test year.

Table 5-1:
Newfoundland Power Customer Base
2023F

Rate	Class of Service	% of Total Customers	% of Total Energy Sales
1.1	Domestic	87.1	60.3
2.1	General Service 0-100 kW (110 kVA)	8.4	14.1
2.3	General Service 110-1000 kVA	0.5	18.2
2.4	General Service 1000 kVA and Over	-[2]	7.0
4.1	Street and Area Lighting	4.0	0.4
Total		**100.0**	**100.0**

The majority of customers served by Newfoundland Power are domestic service customers. Approximately 60% of Newfoundland Power's annual energy sales are to domestic service customers.

5.2.2 Forecast

Newfoundland Power's *Customer, Energy and Demand Forecast* is found in *Volume 2, Supporting Materials, Tab 3*.

The *Customer, Energy and Demand Forecast* reflects the impact of the proposals in this Application.[3] The forecast number of customers and their load requirements are primary inputs used to determine revenue from customer rates.

[2] The 57 customers in Rate #2.4 comprise less than 0.1% of total customers.
[3] See Appendices B and C to the *Customer, Energy and Demand Forecast* found in *Volume 2, Supporting Materials, Tab 3*.

Table 5-2 shows the Company's actual number of customers for 2019 and 2020, and forecast for 2021F, 2022F and 2023F.

Table 5-2:
Number of Customers
2019 to 2023F

	2019	**2020**	**2021F**	**2022F**	**2023F**
Domestic	234,132	235,260	236,199	237,088	237,945
General Service					
0-100 kW (110 kVA)	22,796	22,871	22,925	22,977	23,026
110-1000 kVA	1,267	1,265	1,274	1,269	1,269
1000 kVA and Over	57	59	49[4]	57	57
Total General Service	24,120	24,195	24,248	24,303	24,352
Street and Area Lighting	10,793	10,830	10,851	10,862	10,868
Total Customers	**269,045**	**270,285**	**271,298**	**272,253**	**273,165**

The number of Newfoundland Power customers increased by 0.5% in 2020. The number of customers is forecast to increase by 0.4% in each of 2021 and 2022 and by 0.3% in 2023.

[4] The combined effect of a relatively mild 2020 winter season and public health measures introduced to manage the COVID-19 pandemic caused some customers in the 1000 kVA and Over rate class to move to the 110-1000 kVA rate class. These customers included hotels, retail shopping centres, office buildings, and a transportation facility. It is anticipated that these customers will return to the 1000 kVA and Over rate class in 2022.

Table 5-3 shows the Company's actual energy sales for 2019 and 2020 and forecast for 2021F, 2022F and 2023F based on proposed customer rates.

Table 5-3:
Energy Sales Forecast
2019 to 2023F
(GWh)

	2019	**2020**	**2021F**	**2022F**	**2023F**
Domestic	3,559.8	3,547.0	3,494.8	3,441.4	3,411.9
General Service					
0-100 kW (110 kVA)	797.6	749.4	772.3	796.1	796.6
110-1000 kVA	1,024.2	990.2	1,032.6	1,029.4	1,028.7
1000 kVA and Over	432.0	410.1	389.1	404.5	399.2
Total General Service	2,253.8	2,149.7	2,194.0	2,230.0	2,224.5
Street and Area Lighting	33.0	32.3	30.7	27.9	25.2
Total Energy Sales	**5,846.6**	**5,729.0**	**5,719.5**	**5,699.3**	**5,661.6**

Annual weather-adjusted energy sales are forecast to decrease by approximately 0.8% per year from 2019 to 2023.[5]

Sales to domestic service customers are forecast to decline by approximately 1.0% annually from 2019 to 2023. This forecast decline in energy sales reflects the challenging economic conditions in Newfoundland Power's service territory, including lower housing starts in the province. The forecast decline in energy sales also reflects conservation efforts undertaken by customers, including the installation of heat pumps.[6]

[5] The sales forecast includes elasticity effects of 4.1 GWh in 2022 and 9.2 GWh in 2023 as a result of the proposed March 1, 2022 average rate increase of 0.8%.

[6] Customers installing heat pumps experience annual energy savings of approximately 15%. The penetration of heat pumps among Newfoundland Power's customers increased from approximately 4% in 2014 to approximately 18% in 2020.

Sales to general service customers are forecast to decline by approximately 0.3% annually from 2019 to 2023. This forecast decline in energy sales includes lower customer load requirements associated with construction activities.

Street and area lighting sales are forecast to decline by 5.9% annually from 2019 to 2023. This forecast decline in energy sales reflects the Company's multi-year *LED Street Lighting Replacement Plan*, which will replace all HPS street light fixtures with more energy-efficient LED fixtures commencing in 2021.

Energy sales in 2020 were affected by public health measures introduced by the Provincial Government to manage the COVID-19 pandemic.[7] These public health measures have continued into 2021, but are expected to subside throughout the year as the Provincial Government implements its vaccination plans.[8] Energy sales in 2022 and 2023 are not expected to be affected by public health measures related to the COVID-19 pandemic.

Newfoundland Power forecasts its peak demand to estimate purchased power costs from Hydro throughout the forecast period.[9]

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[7] The Government of Newfoundland and Labrador initiated public health measures to address the spread of COVID-19 in March 2020. On March 18, 2020, a *Public Health Emergency* was declared, resulting in the closure of non-essential businesses and organizations. These measures continued to varying degrees throughout 2020 and contributed to lower general service sales and higher domestic average use in 2020 compared to what the Company has experienced in recent years. See *Customer, Energy and Demand Forecast, Section 4.2 2020 Energy Sales* found in *Volume 2, Supporting Materials, Tab 3*.

[8] On April 8, 2021, the Provincial Government released an update to its *COVID-19 Immunization Timeline*. It indicated that the first dose of COVID-19 vaccines will be available to all eligible residents by July 2021. As of May 16, 2021, approximately 46% of eligible residents in Newfoundland and Labrador had received their first vaccination dose.

[9] Newfoundland Power forecasts peak demand using a load factor based methodology. In 2021, Newfoundland Power revised its demand forecast methodology to use a 5-year average load factor as opposed to a 15-year average load factor. See *Volume 2, Tab 3, Customer, Energy and Demand Forecast, Section 2.5*.

Table 5-4 shows the Company's actual demand for 2019 and 2020 and forecast for 2021F, 2022F and 2023F.

Table 5-4:
Demand Forecast
2019 to 2023F
(MW)

	2019	**2020**	**2021F**	**2022F**	**2023F**
Native Peak[10]	1,367.3	1,299.8	1,350.8	1,350.3	1,341.4
Purchased[11]	1,238.2	1,170.7	1,220.7	1,220.2	1,211.3
Minimum Billing Demand[12]	1,251.1	1,251.1	1,251.1	1,251.1	1,251.1

Newfoundland Power's peak demand was 1,367.3 MW in 2019.[13] The peak demand was 1,299.8 MW in 2020.[14] In 2019 and 2020, the Company's purchased demand was below Hydro's Minimum Billing Demand.[15] Demand is forecast to increase by approximately 3.9% in 2021 and remain steady in 2022. Demand is forecast to decrease by 0.7% in 2023.

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[10] Native peak is the maximum demand served by Newfoundland Power. The 2019 native peak reflects the winter period of December 2019 to March 2020.

[11] Purchased demand is the native peak less the 118.054 MW generation credit and curtailment credit provided for in Hydro's wholesale rate structure. Newfoundland Power's curtailment credit was increased from 11 MW to 12 MW in advance of the 2020-2021 winter season.

[12] Hydro's Utility Rate includes a Minimum Billing Demand for Newfoundland Power. Newfoundland Power's current Minimum Billing Demand was established following Hydro's *2017 General Rate Application* which was approved by the Board in Order No. P.U. 30 (2019). Minimum Billing Demand is 99% of Newfoundland Power's Test Year Native Load (1,392.743 MW) less the Generation Credit (118.054 MW) and Curtailable Credit (11.0 MW) (1,392.743 MW – 118.054 MW – 11.0 MW) x (99%) = 1,251.1 MW. A new Minimum Billing Demand will apply to Newfoundland Power upon the conclusion of Hydro's next general rate application, which is scheduled to be filed with the Board in 2021.

[13] Newfoundland Power's peak demand for the 2019-2020 winter season occurred on Friday, February 21, 2020 at 7:45am.

[14] Newfoundland Power's peak demand for the 2020-2021 winter season occurred on Thursday, February 11, 2021 at 10:15am.

[15] Newfoundland Power's billing demand applies to the year following the winter season in which the demand occurred. The Minimum Billing Demand applied to Newfoundland Power's demand charges in 2020 and also applies to demand charges in 2021.

5.3 RATE CHANGE PLAN

5.3.1 Embedded Cost of Service Study

Recovery of the cost of service is generally accepted as a basic standard in assessing the reasonableness of a utility's rates.[16] 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 2019 costs adjusted to reflect the *pro forma* impact of Hydro's *2017 General Rate Application* on October 1, 2019 (the "Cost of Service Study").[17] The Cost of Service Study is provided in *Volume 2, Supporting Materials, Tab 4*.

Table 5-5 shows the revenue-to-cost ratio for each rate class as indicated by the most recent Cost of Service Study.

Table 5-5:
Cost of Service Study
Revenue-to-Cost Ratios

Class of Service	Rate Code	Revenue-to-Cost Ratios (%)
Domestic	1.1	96.6
General Service 0-100 kW (110 kVA)	2.1	108.5
General Service 110-1000 kVA	2.3	106.8
General Service 1000 kVA and Over	2.4	102.3
Street and Area Lighting	4.1	105.3

[16] Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, Basic Standard of Reasonableness, page 67.

[17] Hydro's *2017 General Rate Application*, which included a 2019 Test Year, was approved by the Board in Order No. P.U. 30 (2019).

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.[18] The revenue-to-cost ratio for each Class of Service is between 90% and 110%. Newfoundland Power is therefore proposing to apply the same rate increase to customers served under each Class of Service.

5.3.2 Rate Design

Newfoundland Power's current customer rates largely reflect the recommendations of the *Retail Rate Review*.[19]

The appropriateness of a utility's rate design requires consideration of the utility's embedded costs and marginal costs.[20] Newfoundland Power's future embedded and marginal costs are largely dependent on the commissioning of the Muskrat Falls Project.[21]

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[18] 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%."*

[19] The *Retail Rate Review* consisted of a comprehensive review of Newfoundland Power's domestic and general service rates and an evaluation of alternative rates. The review commenced following Newfoundland Power's *2008 General Rate Application* and was completed in 2010. Recommendations from the review were implemented, as appropriate, in subsequent years. Proposals approved by the Board in Order No. P.U. 2 (2019) concluded implementation of the recommendations outlined in the *Retail Rate Review.*

[20] Embedded costs refer to actual costs incurred to provide service to customers. Marginal costs refer to costs that are affected by changes in the amount of electricity being consumed.

[21] Since the completion of the Maritime Link transmission line between Newfoundland and Nova Scotia in 2018, Hydro has been engaging in electricity import and export market activities. The completion of the Muskrat Falls generating facility in Labrador and the LIL transmission line from Labrador to Newfoundland will enable greater electricity exports and reduce fuel requirements from Holyrood. Hydro's *Marginal Cost Update – 2018 Summary Report*, filed with the Board on November 15, 2018 provides estimates of the opportunity cost of selling to other jurisdictions. Marginal costs in the future will reflect the potential need for additional on-island capacity as well as the opportunity cost of exporting electricity to other jurisdictions.

The Company's future embedded and marginal costs cannot reasonably be determined until the Muskrat Falls Project is commissioned.[22] The potential requirement for additional capacity to reliably serve Newfoundland Power's customers, which is under review by the Board, adds uncertainty to the Company's marginal cost outlook. [23]

The uncertainty regarding Newfoundland Power's future embedded and marginal costs suggests that changes to the Company's rate designs are not appropriate at this time.

5.4 PROPOSED RATES

5.4.1 General

Schedule A to the Application sets out Newfoundland Power's proposed customer rates to be effective March 1, 2022.

A report on *Customer Rate Impacts* for the domestic and general service classes is provided in *Volume 2, Supporting Materials, Tab 5*.

Exhibit 9 in *Volume 1, Application, Company Evidence and Exhibits* provides a reconciliation of Newfoundland Power's forecast revenue from rates to the Company's revenue requirements for 2022 and 2023.

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[22] See *Section 3.3.2 Risk Assessment* for additional information on the Muskrat Falls Project.

[23] In correspondence dated March 16, 2021 regarding *Reliability and Resource Adequacy Study Review – 2021 Update to the Reliability and Resource Adequacy Study*, Hydro considered the possibility of additional supply requirements due to potential load growth in Labrador. Hydro stated: *"In consideration of providing reliable service, to the extent that incremental resources are required to meet the increased demand and energy requirements, resource options would be pursued based on a least-cost basis to serve the Newfoundland and Labrador Interconnected System. This could result in the development of incremental resources on the island that would reduce the reliance on the LIL during periods of high demand."*

Exhibit 10 in *Volume 1, Application, Company Evidence and Exhibits* provides the computation of the average increase in customer rates of 0.8% proposed by the Company.

Exhibit 11 in *Volume 1, Application, Company Evidence and Exhibits* provides a comparison of Newfoundland Power's existing and proposed customer rates.[24]

5.4.2 Changes to Rate Components

In this Application, Newfoundland Power is not proposing any changes to its domestic, general service, or street and area lighting rate designs.

Domestic

The Company is proposing an increase to customers served under Domestic Service Rate #1.1 and Optional Seasonal Rate #1.1S equal to the overall average increase of 0.8%.

It is proposed that the Basic Customer Charges, Energy Charge, and Minimum Monthly Charges for Domestic Service Rate #1.1 be increased by the average domestic class increase to the extent possible.[25]

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24 The existing and proposed rates reflect the Rate Stabilization Adjustment and the Municipal Tax Adjustment ("MTA") factors effective October 1, 2019.

25 Newfoundland Power's rate design requires that a cost differential be maintained between certain rate components to reflect differences in the cost of providing services. The Company is proposing to maintain a $5.00/month differential for Basic Customer Charges within Domestic Service Rate #1.1 for: (i) services not exceeding 200 Amps; and (ii) services exceeding 200 Amps. This results in the Basic Customer Charge and Minimum Monthly Charge for services exceeding 200 Amps to increase by approximately 0.6% and services not exceeding 200 Amps to increase by 0.8%. Energy charges for Domestic Service Rate #1.1S customers reflect the maintenance of a 2.25¢/kWh differential, with winter season energy charges increasing by 0.8% and non-winter season energy charges increasing by 0.6%.

Rate #2.1 General Service (0-100kW (110 KVA))

Newfoundland Power is proposing an increase to customers served under General Service Rate #2.1 equal to the overall average increase of 0.8%.

It is proposed that the Basic Customer Charges for (i) unmetered service, (ii) single phase service, and (iii) three phase service be subject to the overall Rate #2.1 increase to the extent possible.[26]

It is also proposed that the Energy Charges, Demand Charges and Maximum Monthly Charge be subject to the overall 0.8% increase to the extent possible.[27]

Rate #2.3 General Service (110 – 1000 kVA)

The Company is proposing an increase to customers served under General Service Rate #2.3 equal to the overall average increase of 0.8%.

It is proposed that, on average, the Basic Customer Charge, Energy Charge, Demand Charges and Maximum Monthly Charge be subject to the overall Rate #2.3 Class increase to the extent possible.[28]

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[26] The Company is proposing to maintain: (i) the $8 cost differential between basic customer charges for unmetered and single phase service; and (ii) the $12 cost differential between basic customer charges for single phase service and three phase service. The result is increases of 1.4%, 0.8%, and 0.5% for the unmetered, single phase, and three phase Basic Customer Charges, respectively.

[27] Newfoundland Power is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate #2.1. Maintaining this differential will result in the winter Demand Charge increasing by 0.6% and non-winter Demand Charge increasing by 0.8%.

[28] Newfoundland Power is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate #2.3. Maintaining this differential will result in the winter Demand Charge increasing by 0.7% and non-winter Demand Charge increasing by 1.1%.

Rate #2.4 General Service (1000 kVA and Over)

The Company is proposing an increase to customers served under General Service Rate #2.4 equal to the overall average increase of 0.8%.

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.[29]

Rate #4.1 Street and Area Lighting Service

The Company is proposing an increase to street and area lighting service rates equal to the overall average increase of 0.8%.[30]

[29] Newfoundland Power is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate #2.4. Maintaining this differential will result in the winter Demand Charge increasing by 0.5% and non-winter Demand Charge increasing by 0.7%.

[30] Street and area lighting rates will continue to be developed based on recovered 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.

Newfoundland Power Inc.

Operating Costs by Function
2019 to 2023F
($000s)

	Function	**Actual 2019**	**Actual 2020**	**Forecast 2021**	**Forecast 2022**	**Forecast 2023[1]**
1	Distribution	10,236	10,945	9,227	9,487	9,741
2	Transmission	712	919	957	978	999
3	Substations	2,361	2,258	2,356	2,422	2,487
4	Power Produced	3,940	3,797	3,930	4,027	4,122
5	Administrative & Engineering Support	7,972	7,934	8,204	8,433	8,657
6	Telecommunications	1,286	1,299	1,350	1,374	1,397
7	Environment	287	273	282	289	296
8	Fleet Operations & Maintenance	1,679	1,719	1,666	1,695	1,723
9						
10	**Electricity Supply**	**28,473**	**29,144**	**27,972**	**28,705**	**29,422**
11						
12	Customer Service	7,726	7,468	7,875	8,038	8,103
13	Conservation	728	679	782	886	946
14	Uncollectible Bills	1,980	2,290	2,135	2,172	2,208
15						
16	**Customer Services**	**10,434**	**10,437**	**10,792**	**11,096**	**11,257**
17						
18	Information Systems	5,402	5,855	6,051	6,407	7,311
19	Financial Services	1,787	1,806	1,886	1,942	1,997
20	Corporate & Employee Services	14,233	14,504	15,529	16,052	16,267
21	Insurances	1,397	1,698	2,079	2,306	2,345
22						
23	**General**	**22,819**	**23,863**	**25,545**	**26,707**	**27,920**
24						
25	**Gross Operating Cost**	**61,726**	**63,444**	**64,309**	**66,508**	**68,599**

[1] For comparison purposes, 2023 forecast gross operating costs exclude changes resulting from the *Review of General Expenses Capitalized*.

Newfoundland Power Inc.

Operating Costs by Breakdown
2019 to 2023F
($000s)

	Breakdown	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023[1]
1	Regular and Standby	30,068	31,483	30,703	31,677	32,634
2	Temporary	2,151	1,625	1,990	2,050	2,108
3	Overtime	3,022	3,425	3,204	3,300	3,394
4	**Total Labour**	**35,241**	**36,533**	**35,897**	**37,027**	**38,136**
5						
6	Vehicle Expenses	1,681	1,725	1,673	1,702	1,730
7	Operating Materials	1,359	1,300	1,244	1,266	1,287
8	Inter-Company Charges	27	26	27	27	28
9	Plants, Subs, System Oper & Bldgs	3,267	3,484	3,376	3,434	3,492
10	Travel	1,089	633	861	876	891
11	Tools and Clothing Allowance	1,289	1,156	1,223	1,244	1,265
12	Miscellaneous	1,450	1,633	1,542	1,568	1,595
13	Taxes and Assessments	1,156	1,116	1,142	1,162	1,181
14	Uncollectible Bills	1,980	2,290	2,135	2,172	2,208
15	Insurance	1,397	1,698	2,079	2,306	2,345
16	Severance & Other Employee Costs	132	126	129	131	133
17	Education, Training, Employee Fees	418	267	343	348	354
18	Trustee and Directors' Fees	518	673	689	701	712
19	Other Company Fees	2,428	2,131	2,610	2,868	2,874
20	Stationery & Copying	257	246	252	256	260
21	Equipment Rental/Maintenance	790	656	770	832	897
22	Telecommunications	1,473	1,473	1,535	1,562	1,588
23	Postage	1,329	1,313	1,283	1,244	1,202
24	Advertising	573	460	517	525	534
25	Vegetation Management	2,042	2,306	2,359	2,401	2,441
26	Computing Equipment & Software	1,830	2,199	2,623	2,856	3,446
27	**Total Other**	**26,485**	**26,911**	**28,412**	**29,481**	**30,463**
28						
29	**Gross Operating Cost**	**61,726**	**63,444**	**64,309**	**66,508**	**68,599**

[1] For comparison purposes, 2023 forecast gross operating costs exclude changes resulting from the *Review of General Expenses Capitalized*.

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Statements of Income
($000s)

	Actual		Forecast		
	2019	**2020**	**2021**	**2022E**	**2023E**
Revenue from rates	684,179	715,627	712,338	711,562	708,398
Transfers from (to) the RSA	(13,339)	(8,786)	(11,336)	(17,328)	(22,035)
	670,840	706,841	701,002	694,234	686,363
Purchased power expense	456,512	470,275	465,872	465,610	461,686
Demand management incentive account adjustments	(2,687)	(1,431)	(1,812)	(1,811)	(2,079)
Wholesale rate change flow-through	(8,964)	-	-	-	-
	444,861	468,844	464,060	463,799	459,607
Contribution	225,979	237,997	236,942	230,435	226,756
Other revenue[1]	7,899	7,226	5,651	4,746	4,679
Other expenses:					
Operating expenses[2]	61,705	64,200	65,310	67,347	69,736
Employee future benefit costs[3]	9,575	14,391	14,678	8,745	6,159
Deferred cost recoveries and amortizations	1,752	(876)	(876)	-	-
Depreciation[4]	62,066	64,982	67,739	70,424	74,745
Finance charges[5]	35,061	36,719	34,711	34,605	32,935
	170,159	179,416	181,562	181,121	183,575
Income before income taxes	63,719	65,807	61,031	54,060	47,860
Income taxes[6]	18,324	19,338	17,698	15,384	13,294
Net income	45,395	46,469	43,333	38,676	34,566
Preferred dividends	550	347	-	-	-
Earnings applicable to common shares[6]	44,845	46,122	43,333	38,676	34,566
Rate of Return and Credit Metrics					
Rate of Return on Rate Base (%)	6.97	7.04	6.46	5.90	5.23
Regulated Return on Book Equity (%)	8.79	8.93	8.24	7.16	6.34
Interest Coverage (times)	2.4	2.4	2.4	2.2	2.0
CFO Pre-W/C + Interest / Interest (times)	4.0	4.6	4.9	4.7	5.0
CFO Pre-W/C / Debt (%)	17.4	21.1	20.6	18.7	19.2

[1] Shown after reclassification of other contract costs and equity portion of AFUDC.

[2] Shown after adjustment for non-regulated expenses and reclassification of other contract costs and current portion of employee future benefit costs.

[3] Shown after reclassification of current portion of employee future benefit costs.

[4] Shown after reclassification of tax on cost of removal.

[5] Shown after reclassification of equity portion of AFUDC.

[6] Shown after adjustment for non-regulated expenses and reclassification of tax on cost of removal.

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Statements of Retained Earnings
($000s)

		Actual		Forecast		
		2019	**2020**	**2021**	**2022E**	**2023E**
1	Balance - Beginning	432,588	447,546	445,330	465,487	473,541
2	Net income for the period	42,891	43,577	40,922	36,327	32,073
3	Allocation of Part VI.1 tax	275	625	598	624	624
4		475,754	491,748	486,850	502,438	506,238
5						
6	Dividends					
7	Preference shares	550	347	-	-	-
8	Common shares	27,658	46,071	21,363	28,897	29,310
9		28,208	46,418	21,363	28,897	29,310
10	Balance - End of Period	447,546	445,330	465,487	473,541	476,928

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Balance Sheets
($000s)

	Actual		Forecast		
	2019	**2020**	**2021**	**2022E**	**2023E**
Assets					
Current Assets					
Accounts receivable	83,552	65,681	95,069	85,681	79,999
Income taxes receivable	2,038	-	-	-	-
Materials and supplies	1,479	1,705	1,745	1,775	1,805
Prepaid expenses	2,190	2,522	2,580	2,625	2,669
Regulatory assets	16,771	14,560	(13,375)	(18,943)	(19,449)
Related party notes receivable	-	8,000	-	-	-
	106,030	92,468	86,019	71,138	65,024
Property, plant and equipment	1,204,308	1,237,470	1,289,977	1,326,460	1,381,735
Intangible assets	28,131	30,592	40,890	57,193	61,893
Regulatory assets	347,137	331,302	311,384	305,142	300,958
Defined benefit pension plans	15,193	25,705	33,838	42,344	51,258
Other assets	2,608	2,169	2,183	2,201	2,225
	1,703,407	1,719,706	1,764,291	1,804,478	1,863,093
Liabilities and shareholders' equity					
Current Liabilities					
Short-term borrowings	1,412	6,728	-	-	-
Accounts payable and accrued charges	90,337	74,110	81,597	85,886	92,024
Interest payable	6,628	6,596	6,420	7,153	7,070
Income taxes payable	-	1,842	-	-	-
Defined benefit pension plans	221	438	245	227	221
Other post employment benefits	3,710	3,782	3,647	3,922	4,174
Regulatory liabilities	10,773	8,769	1,512	(724)	(832)
Current instalments of long-term debt	36,200	7,200	35,200	7,550	7,550
Related Party Borrowings	50,500	-	-	-	-
	199,781	109,465	128,621	104,014	110,207
Regulatory liabilities	175,826	197,944	190,113	199,987	213,169
Defined benefit pension plans	5,407	5,180	5,278	5,402	5,544
Other post employment benefits	88,316	90,676	92,641	94,508	96,307
Other liabilities	1,420	1,212	1,212	1,212	1,212
Deferred income taxes	173,249	175,356	175,939	176,163	184,812
Long-term debt	532,692	624,222	634,679	679,330	704,593
Shareholders' equity					
Common shares	70,321	70,321	70,321	70,321	70,321
Preference shares	8,849	-	-	-	-
Retained earnings	447,546	445,330	465,487	473,541	476,928
	526,716	515,651	535,808	543,862	547,249
	1,703,407	1,719,706	1,764,291	1,804,478	1,863,093

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Statements of Cash Flows
($000s)

	Actual		Forecast		
	2019	2020	2021	2022E	2023E
Operating Activities					
Net Earnings	42,891	43,577	40,922	36,327	32,073
Items Not Affecting Cash:					
Depreciation of property, plant and equipment	64,609	67,327	70,074	72,771	75,591
Amortization of intangible assets and other	3,644	4,092	4,324	4,565	6,337
Change in long-term regulatory assets and liabilities	(2,764)	24,029	22,915	20,419	22,740
Deferred income taxes	5,160	(5,111)	(478)	224	8,649
Employee future benefits	(1,707)	2,697	2,151	(3,772)	(6,695)
Other	(595)	197	6	(250)	(709)
	111,238	136,808	139,914	130,284	137,986
Change in working capital	13,240	8,957	(31,061)	(2,381)	(6,717)
	124,478	145,765	108,853	127,903	131,269
Investing Activities					
Capital expenditures	(106,047)	(95,437)	(115,111)	(97,650)	(118,691)
Intangible asset expenditures	(6,900)	(6,320)	(14,412)	(20,670)	(10,854)
Contribution from customers and security deposits	8,278	2,102	2,500	2,500	2,500
Other	-	-	(20)	(7)	(6)
	(104,669)	(99,655)	(127,043)	(115,827)	(127,051)
Financing Activities					
Change in short-term borrowings	1,412	5,316	(6,728)	-	-
Net (repayment) proceeds of committed credit facility	(37,000)	-	45,481	(21,829)	32,642
Proceeds from long-term debt	-	100,000	-	75,000	-
Repayment of long-term debt	(6,600)	(37,200)	(7,200)	(35,950)	(7,550)
Net proceeds (repayment) from related party loan	50,500	(58,500)	8,000	-	-
Payment of debt financing costs	(35)	(459)	-	(400)	-
Redemption of preference shares	(62)	(8,849)	-	-	-
Dividends					
Preference shares	(550)	(347)	-	-	-
Common shares	(27,658)	(46,071)	(21,363)	(28,897)	(29,310)
	(19,993)	(46,110)	18,190	(12,076)	(4,218)
Change in Cash	(184)	-	-	-	-
Cash, Beginning of Year	184	-	-	-	-
Cash, End of Year	-	-	-	-	-

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Average Rate Base[1]
($000s)

	Actual		Forecast		
	2019	**2020**	**2021**	**2022E**	**2023E**
Plant Investment	1,096,310	1,133,996	1,171,625	1,209,201	1,261,498
Additions to Rate Base					
Defined Benefit Pension Costs	90,751	90,863	89,400	91,526	98,201
Deferred Credit Facility Costs	91	54	39	24	10
Cost Recovery Deferral - Hearing Costs	247	371	124	-	-
Cost Recovery Deferral - Conservation	16,630	17,210	17,273	17,841	18,343
Cost Recovery Deferral - Electrification	-	-	468	935	935
Weather Normalization Reserve	3,586	961	(3,824)	(1,958)	-
Demand Management Incentive Account	941	1,441	1,135	1,268	1,361
Customer Finance Programs	2,477	2,296	2,123	2,166	2,202
	114,723	113,196	106,738	111,802	121,052
Deductions from Rate Base					
Other Post Employment Benefits	59,452	64,265	69,426	74,950	80,572
Customer Security Deposits	1,246	1,316	1,212	1,212	1,212
Accrued Pension Obligation	5,060	5,181	5,311	5,430	5,578
Accumulated Deferred Income Taxes	7,488	11,386	13,674	15,997	23,784
Cost Recovery Deferrals	613	920	307	-	-
	73,859	83,068	89,930	97,589	111,146
Average Rate Base Before Allowances	1,137,174	1,164,124	1,188,433	1,223,414	1,271,404
Cash Working Capital Allowance	9,907	10,503	10,362	10,326	10,096
Materials and Supplies Allowance	6,475	7,270	8,219	8,218	8,358
Average Rate Base at Year End	1,153,556	1,181,897	1,207,014	1,241,958	1,289,858

[1] All amounts shown are averages.

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Weighted Average Cost of Capital
($000s)

		Actual		Forecast		
		2019	**2020**	**2021**	**2022E**	**2023E**
1	**Average Capitalization**					
2	Debt	616,343	629,385	653,961	678,353	699,501
3	Preference Shares[1]	8,880	4,425	-	-	-
4	Common Equity	510,388	516,759	525,730	539,835	545,556
5		1,135,611	1,150,569	1,179,691	1,218,188	1,245,057
6						
7	**Average Capital Structure (%)**					
8	Debt	54.28	54.70	55.43	55.69	56.18
9	Preference Shares	0.78	0.39	-	-	-
10	Common Equity	44.94	44.91	44.57	44.31	43.82
11		100.00	100.00	100.00	100.00	100.00
12						
13	**Cost of Capital (%)**					
14	Debt[2]	5.68	5.83	5.31	5.10	4.71
15	Preference Shares	6.19	7.84	-	-	-
16	Common Equity	8.79	8.93	8.24	7.16	6.34
17						
18						
19	**Weighted Average Cost of Capital (%)**					
20	Debt	3.08	3.19	2.94	2.84	2.64
21	Preference Shares	0.05	0.03	-	-	-
22	Common Equity	3.95	4.01	3.67	3.17	2.78
23		7.08	7.23	6.61	6.01	5.42

[1] On January 2, 2020, the Company provided notice to shareholders of the redemption of all the issued and outstanding First Preference Shares. These shares comprised approximately $8.8 million of the Company's capital structure as of the notice date. On February 3, 2020, the Company redeemed all of the issued and outstanding First Preference Shares.

[2] Cost of debt is shown net of AFUDC. This is consistent with the cost of debt used in the calculation of return on rate base. For regulatory reporting purposes, the embedded cost of debt shown in Return 25 of the 2019 and 2020 Annual Reports to the Board can be reconciled to the reported cost of debt above as follows:

	2019	2020
Cost of Debt (Line 14) (%)	5.68	5.83
AFUDC (%)	0.32	0.15
Cost of Debt - Return 25 (%)	6.00	5.98

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Rate of Return on Rate Base
($000s)

		Actual		Forecast		
		2019	**2020**	**2021**	**2022E**	**2023E**
1	Regulated Return on Equity	44,845	46,122	43,333	38,676	34,566
2	Return on Preferred Equity	550	347	-	-	-
3		45,395	46,469	43,333	38,676	34,566
4						
5	Finance Charges					
6	Interest on Long-Term Debt	35,375	36,811	35,452	36,005	34,945
7	Other Interest	1,355	609	348	328	752
8	Amortization of Bond Issue Expenses	235	233	212	197	183
9	AFUDC	(1,933)	(949)	(1,317)	(1,943)	(2,963)
10		35,032	36,704	34,695	34,587	32,917
11						
12	Return on Rate Base	80,427	83,173	78,028	73,263	67,483
13						
14	Average Rate Base	1,153,556	1,181,897	1,207,014	1,241,958	1,289,858
15						
16	Rate of Return on Rate Base (%)	6.97	7.04	6.46	5.90	5.23

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Inputs and Assumptions

Energy Forecasts:	Energy forecasts are based on economic indicators taken from the Conference Board of Canada Economic Forecast, dated February 24, 2021.
Revenue Forecast:	The revenue forecast is based on the Customer, Energy and Demand forecast dated May 2021.
	Revenue for 2019 through 2021F reflects: (i) recovery through the RSA of amounts associated with the Energy Supply Cost Variance Adjustment Clause; (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs; (iii) recovery through the RSA of amounts associated with the July 1, 2017 Hydro supply cost rate increase; (iv) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (v) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 13 (2013), P.U. 18 (2015), P.U. 23 (2017), P.U. 20 (2018), P.U. 2 (2019) and P.U. 31 (2019).
Purchased Power Expense:	Purchased power expense reflects Newfoundland & Labrador Hydro's rates approved by the Board effective October 1, 2019 and the Customer, Energy and Demand Forecast dated May 12, 2021.
	Purchased power expense reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007). This mechanism provides for recovery of demand costs that are in excess of unit demand costs included in the most recent test year.
	Purchased power expense reflects the operation of the wholesale rate change flow-through account resulting from the implementation of the Revised Utility Base Rate as approved in Order No. P.U. 30 (2019).
Employee Future Benefit Costs:	Pension funding is based on the actuarial valuation dated as at December 31, 2019.
	Pension discount rate is 3.80% for 2019, 3.10% for 2020 and 2.60% for 2021 through 2023.
	Expected return on pension plan assets is 5.25% for 2019, 4.75% for 2020 and 4.50% for 2021 through through 2023.
	OPEBs discount rate is 3.90% for 2019, 3.20% for 2020 and 2.70% for 2021 through 2023.
Cost Recovery Deferrals:	The 2021 to 2023 forecasts include the deferred recovery over a 7-year period of certain conservation program costs as reflected in the Application.
	The 2021 forecast includes the deferred recovery over a 34-month period of $1.0 million in external costs related to the *2019/2020 General Rate Application* beginning March 1, 2019.
	The 2021 forecast includes the amortization over a 34-month period of a $2.5 million revenue surplus related to a March 1, 2019 rate implementation date beginning March 1, 2019.
Depreciation Rates:	Depreciation rates are based on the *2014 Depreciation Study.*

Newfoundland Power Inc.

Financial Performance
2019 to 2023E
Inputs and Assumptions

Operating Costs: The operating forecast for 2021 reflects the most recent management estimates. Operating forecasts for 2022 and 2023 reflect projected increases of 3.00% in 2022 and 2.85% in 2023 for labour, and non-labour increases based upon the GDP deflator.

Capital Expenditure: Capital Expenditures for 2021 through 2023 are based on the *2022 Capital Budget Application* adjusted for known carryovers.

Short-Term Interest Rates: Average short-term interest rates are forecast to be 1.24% for 2021, 1.36% for 2022 and 1.70% for 2023.

Long-Term Debt: A $75.0 million long-term debt issue is forecast to be completed in March 2022. The debt is forecast for 30 years at a coupon rate of 4.25%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

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

Income Tax: Income tax expense reflects a statutory income tax rate of 30% for 2021 through 2023.

Credit Rating Reports:
Moody's and DBRS

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
16 November 2020

Update

Rate this Research

RATINGS

Newfoundland Power Inc.

Domicile	St. John's, Newfoundland, Canada
Long Term Rating	Baa1
Type	LT Issuer Rating - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Newfoundland Power Inc.

Update to credit analysis

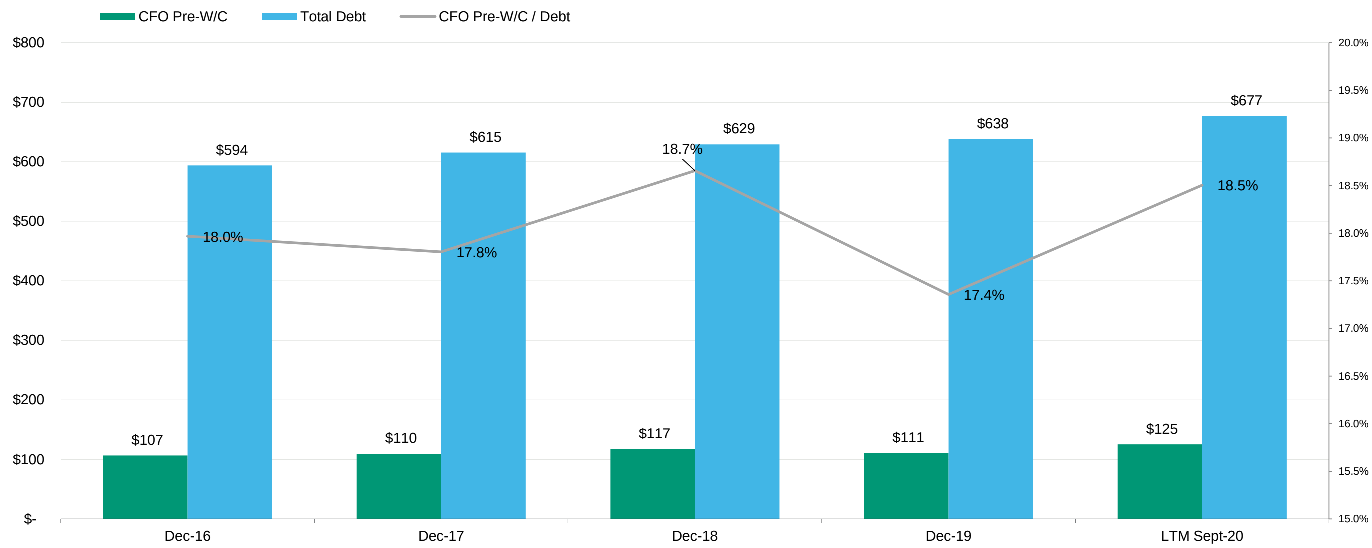
Summary

Newfoundland Power Inc.'s (NPI, Baa1 stable) credit profile reflects the company's low business risk as a primarily electric transmission and distribution cost-of-service regulated utility with no unregulated business activities. Approximately 93% of NPI's power requirements are purchased from provincially owned Newfoundland & Labrador Hydro ("Hydro"), the cost of which is passed through to ratepayers. We view the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) as one of the more supportive regulators in Canada because regulatory decisions are timely and balanced, deferral accounts reduce risks from factors beyond management's control and NPI's 45% equity capital is among the highest authorized levels in Canada. A January 2019 order from the PUB approved a rate case settlement for the years 2019-2020 and maintained both NPI's allowed Return on Equity (ROE) at 8.5% and 45% equity capital through 2021. The credit profile is negatively impacted by the risk of future cost recovery associated with the Province of Newfoundland and Labrador's sizeable Muskrat Falls hydroelectric project. This politically sensitive project is large relative to the provincial economy and may place considerable upward pressure on the future electricity rates of NPI, a credit negative. NPI's senior secured first mortgage bonds (FMB) rating reflects the first mortgage security over NPI's property, plant and equipment and a floating charge on all other assets.

COVID-19 developments

The rapid spread of the coronavirus outbreak, severe global economic shock, low oil prices, and asset price volatility are creating a severe and extensive credit shock across many sectors, regions and markets. The combined credit effects of these developments are unprecedented. We regard the coronavirus outbreak as a social risk under our ESG framework given the substantial implications for public health and safety. We expect NPI will be relatively resilient to recessionary pressures because of its rate regulated business model and regulatory mechanisms. Nevertheless, we are watching for electricity usage declines, utility bill payment delinquency, and the regulatory response to counter these effects on earnings and cash flow.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt
(CAD million)



Source: Moody's Financial Metrics

Credit strengths

» Low risk regulated utility, primarily transmission and distribution, with 93% purchased power from provincial generators

» Supportive regulatory environment

» Stable cash flow coverage metrics

Credit challenges

» Upward pressure on rates due to the Muskrat Falls project

» Increased risks of delayed cost recovery upon completion Muskrat Falls expected in 2021

Rating outlook

The stable outlook reflects the PUB's regulation of NPI which we consider credit supportive. We expect the regulatory environment to remain supportive, with the company maintaining a suite of timely recovery mechanisms, along with our view that relatively stable cash flow generation and the capital structure of NPI will generate sustained CFO pre-WC to debt in the 16-18% range.

Factors that could lead to an upgrade

NPI's rating could be upgraded if CFO pre-WC to debt is forecast to be sustained above 18%. However, an upgrade of NPI's rating is unlikely without further clarity on the timing, size and implications of the increases in electricity rates related to the Muskrat Falls hydroelectric project.

Factors that could lead to a downgrade

NPI's rating could be downgraded if there is a meaningful reduction in the level of regulatory support combined with a sustained deterioration in NPI's financial metrics such as CFO pre-WC to debt falling below 14%.

Key indicators

Exhibit 2
Newfoundland Power Inc. [1]

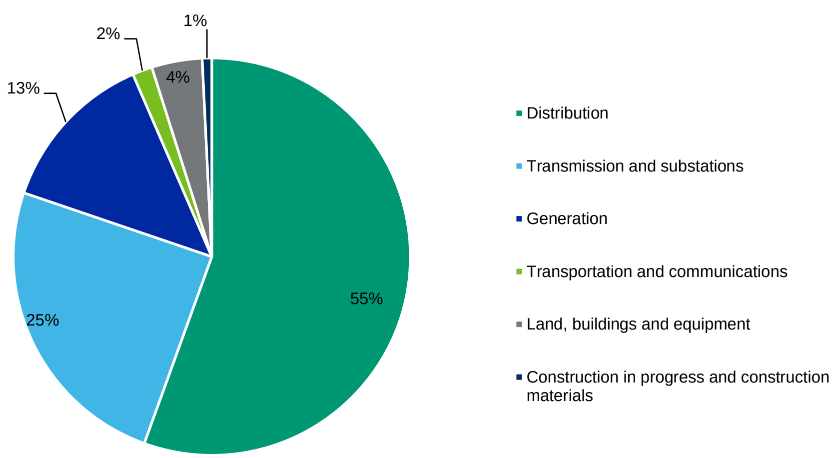
	Dec-16	Dec-17	Dec-18	Dec-19	LTM Sept-20
CFO Pre-W/C + Interest / Interest	4.0x	4.0x	4.2x	4.0x	4.4x
CFO Pre-W/C / Debt	18.0%	17.8%	18.7%	17.4%	18.5%
CFO Pre-W/C – Dividends / Debt	14.4%	11.6%	14.3%	13.0%	14.3%
Debt / Capitalization	48.8%	48.9%	48.8%	48.1%	49.4%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Headquartered in St. John's, Newfoundland, NPI is primarily an electric transmission distribution utility serving a customer base of approximately 269,000. NPI operates under cost of service regulation and is regulated by the PUB under the Public Utilities Act (the Act). NPI purchases the majority of its power from Newfoundland and Labrador Hydro (Hydro, not rated) which is indirectly held, but wholly owned by the Province of Newfoundland & Labrador. NPI's installed generating capacity is 143 MW, including 97 MW of hydro. NPI is a wholly-owned subsidiary of Fortis Inc. (FTS: Baa3 stable), which is primarily a diversified electric and gas utility holding company also based in St. John's.

Exhibit 3
2019 Net Property, Plant and Equipment by segment
Newfoundland Power Inc.



Source: NPI's 2019 AR

Detailed credit considerations

Low-risk business model

NPI's credit profile reflects the company's low business risk as a cost of service regulated utility. NPI owns and operates a transmission and distribution utility located on the island portion of the province of Newfoundland and Labrador and dominates that market, which is geographically isolated and effectively protected from potential competition. NPI serves roughly 87% of the province's electricity customers. The market is mature and NPI's electricity sales have tended to be relatively stable. Historically, growth has not taxed NPI either operationally or financially due to relatively timely recovery of capital and operating costs.

NPI owns some generation assets that are regulated and represent only 13% of NPI's net property, plant and equipment at year-end 2019. Accordingly, we consider the business risk of NPI to be similar to that of a transmission and distribution utility rather than that of a typical vertically integrated utility, which is often exposed to commodity price risk and the operational, financial and environmental risks associated with electricity generation.

However, NPI faces uncertainties due to the timing and size of expected rate increases associated with Nalcor Energy Inc's Muskrat Falls hydroelectric project. The total cost (including financing) of Muskrat Falls and associated transmission in Newfoundland and Labrador has increased to about CAD13.1 billion and the date of full power has been pushed back to 2021. In February 2020, the Province and the Government of Canada have agreed to undertake a financial restructuring of the project in an effort to mitigate the increase in rates, however the potential for rate shock remains. While NPI is allowed to pass through the increase in power supply costs to customers, the utility remains exposed to volume risk. The increase in rates from the project may lead to lower electricity demand than currently anticipated, resulting in lower revenues and cash flow.

Supportive regulatory environment

NPI's operations benefit from a well-developed regulatory framework and business environment that we consider credit supportive. PUB's regulation of NPI is credit supportive primarily because of a track record of reasonably timely and balanced decisions that enable NPI to generate stable and predictable cash flow and earn its allowed ROE which has not been directly subject to political interference. NPI has access to the courts for disputes with the PUB.

The PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly reduce the risk of cost disallowances and support NPI's ability to fully recover costs on a timely basis. NPI submits a proposed capital plan for PUB approval annually before the next fiscal year. Furthermore, NPI is required to obtain PUB pre-approval for the issuance of any FMB or the incurrence of credit facilities with maturities exceeding one year, which we see as credit positives.

Several other cost recovery mechanisms reduce NPI's exposure to unexpected costs due to variations in purchased power costs, weather, pension and other post-employment benefit (OPEB) costs. While NPI foregoes some upside potential, the stability and predictability of its cash flows are increased. For example, the Rate Stabilization Account (RSA) facilitates timely recovery of purchased power costs in excess of those forecasted for ratemaking purposes. This is particularly important since the marginal cost of power that NPI obtains from Hydro exceeds the average supply costs embedded in customer rates. The RSA provides for the amortization of the under or over collection over a 12 month period. Other mechanisms include the Weather Normalization Account, Conservation and Demand Management Deferral and the Demand Management Incentive Account (which limits NPI's exposure to variations in purchased power costs to 1% of demand costs reflected in the test year for ratemaking purposes).

NPI is allowed to file a rate application based on a forward test year and forecast rate base. We view these mechanisms positively because they reduce revenue lag associated with large capital projects. A settlement agreement regarding NPI's 2019-2020 rate application was approved by the regulator in January 2019. NPI's allowed ROE of 8.5% for the period 2019-2021 remains unchanged compared to the 2016-2018 period. While the ROE remains relatively low, it is mitigated by one of the highest deemed equity levels in Canada at 45%. We expect the company to file its next rate application by June 2021.

Exhibit 4
Historical Approved ROE, Approved Equity thickness and Rate Base
Newfoundland Power Inc.

	2013	2014	2015	2016	2017	2018	2019	2020
Approved Return on Equity (ROE)	8.8%	8.8%	8.8%	8.5%	8.5%	8.5%	8.5%	8.5%
Approved Equity thickness	45%	45%	45%	45%	45%	45%	45%	45%
Midyear Rate base, CAD billion	0.9	1.0	1.0	1.1	1.1	1.1	1.2	1.2

Source: NPI's financial statements, Fortis Inc's presentations, NPI's 2019-2020 rate application

Stable cash flow coverage metrics

We expect the company to continue to generate predictable cash flow, a key credit strength. Driving this stability, the company's net income is a function of its allowed return on equity, its deemed capital structure (equity thickness) and rate base. The other large component of it's predictable cash flow is depreciation and amortization. We expect NPI to continue to achieve sustainable CFO pre-W/C to debt consistent with our expectations and the current credit profile.

Exhibit 5
Historical CFO Pre-W/C Breakdown
Newfoundland Power Inc.

(in CN$ Millions)	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-19	LTM Ending Sep-20
As Adjusted						
Net Income	**38.8**	**40.0**	**41.0**	**41.2**	**42.3**	**37.0**
Depreciation	54.2	57.7	59.9	62.0	64.6	66.8
Amortization of Investments	2.8	3.0	3.3	3.4	3.6	3.9
Deferred income taxes and itc	(0.7)	(0.4)	2.3	(2.9)	5.2	(3.6)
Other	4.5	4.1	2.6	2.7	(2.3)	1.6
Funds from Operations	**99.5**	**104.4**	**109.0**	**106.4**	**113.5**	**105.6**
Changes in Other Oper. Assets & Liabilities - LT	2.9	2.3	0.5	11.0	(2.8)	19.7
CFO Pre-W/C	**102.4**	**106.7**	**109.6**	**117.4**	**110.7**	**125.3**

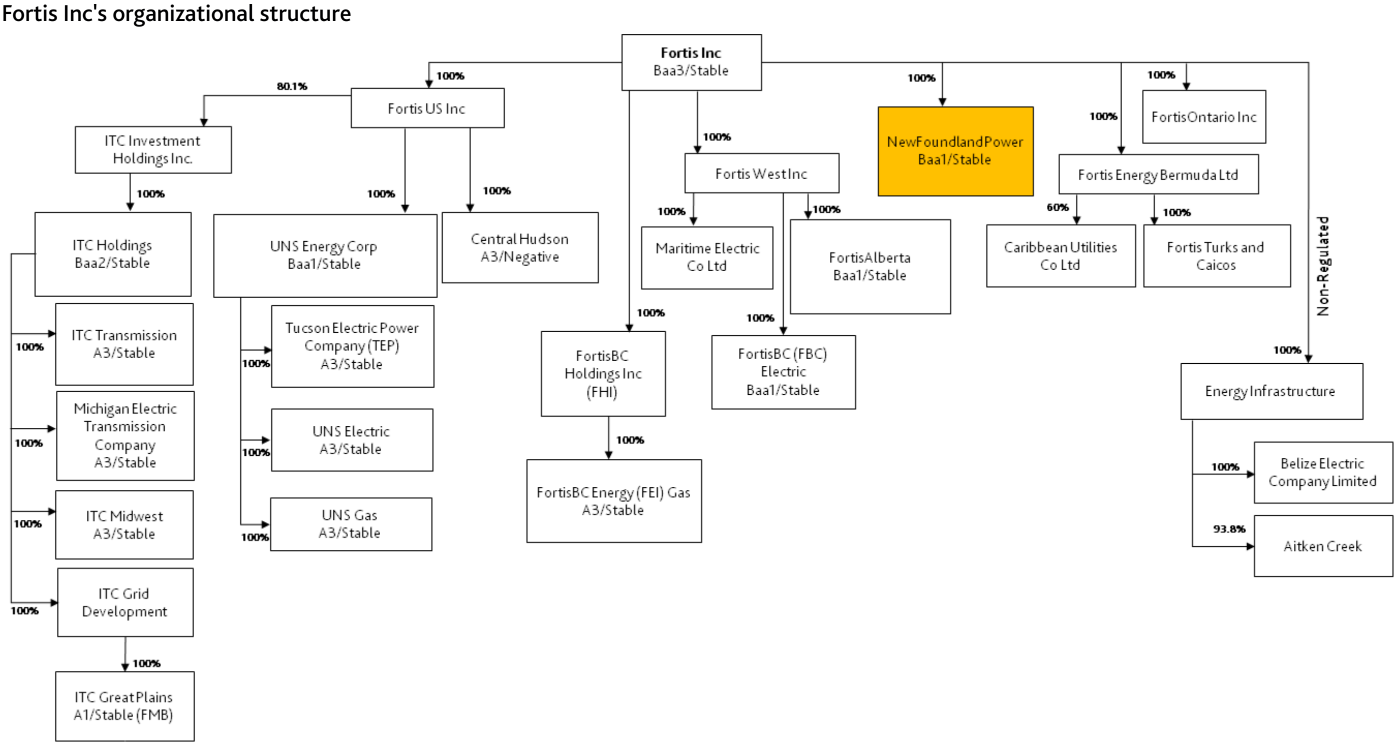
All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

NPI is independent of Fortis Inc.

While NPI is one of a number of utility operating companies owned by FTS, we consider NPI, like sister companies FortisAlberta Inc. (FAB: Baa1 stable), FortisBC Inc. (FBC: Baa1 stable) and FortisBC Energy Inc. (FEI: A3 stable), to be operationally and financially independent of FTS, a credit positive. FTS has consistently demonstrated good management and support of its subsidiaries and we view NPI's access to the executive and strategic support of FTS to be a credit positive.

FTS is a highly leveraged holding company and is reliant on distributions from its subsidiaries to finance its obligations, a credit negative for NPI. The weaker credit quality of FTS does not materially constrain the credit profile of NPI. While we think it is highly unlikely, if required, and consistent with FTS precedent, we assume that FTS would provide extraordinary financial support to NPI, provided that the parent had the economic incentive and sufficient resources to do so.

Exhibit 6
Fortis Inc's organizational structure



Source: Fortis Inc

ESG considerations

Environmental

NPI has low carbon transition risk. Approximately 93% of NPI's power requirements are purchased from provincially owned Newfoundland and Labrador Hydro, the cost of which is passed through to ratepayers. NPI’s PP&E is comprised of just 13% generation assets (the majority of which are small hydro electric generating stations); most of NPI’s business consists of transmission and distribution (T&D), which we view as having low carbon transition risk because T&Ds have limited direct exposure to fuel costs.

Social

The utility sector has moderate social risks compared to other industries. NPI is a member of the Canadian Electricity Association (CEA) and participates in its Sustainable Electricity Program (SEP). As a member of the CEA, NPI is an active participant in the Sustainable Electricity Program, which is comprised of sustainable development and corporate responsibility, reporting of annual ESG performance indicators, oversight by an external Public Advisory Panel, and verification of its commitment to the program by an external independent third party.

Given the current situation related to the coronavirus pandemic, there is a possibility of increasing social risk as the affordability of the utility bill and prolonged recessionary impact could have negative implications for NPI.

Governance

NPI's governance is influenced by its ultimate parent, FTS and is similar to other FTS owned subsidiaries. A key financial policy for NPI is to maintain the capital structure established with any dividends paid to FTS. 6 of NPI's 10 directors are independent. Moody's framework for assessing corporate governance is discussed in “Utilities and power companies – North America Corporate governance assessments show generally credit friendly characteristics” (September 19, 2019).

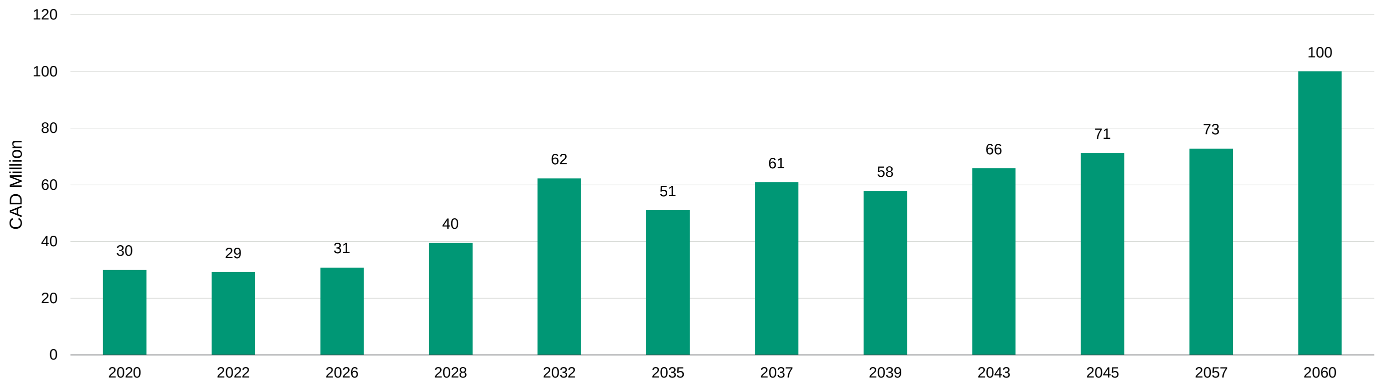
Liquidity analysis

We consider, NPI's liquidity arrangements to be adequate in the context of its relatively stable cash flow and funding requirements.

NPI plans to spend about CAD97 million on capital expenditures in 2020 and NPI plans to pay dividends in amounts commensurate with maintaining the 45% deemed equity layer. With estimated cash flow from operations to be in the range of CAD100-120 million, we expect that any modest free cash flow shortfall will be funded through NPI's bank credit facilities and adjustments to dividends paid.

The company's core liquidity facility is a CAD100 million committed revolving credit facility that matures in August 2024. While the credit agreement contains a covenant that NPI maintain its debt to capitalization ratio at or below 65%, it does not include a material adverse change (MAC) clause or representation and warranty declaration prior to drawdown. There was nothing drawn under the committed facility at 30 September 2020. The company repaid CAD30 million in first mortgage sinking fund bonds due in October 2020 and its next debt maturity is in June 2022.

Exhibit 7
Long-term Debt Maturity as of 30 September 2020
Newfoundland Power Inc.



NPI's debt consists of first mortgage sinking fund bonds.
Source: NPI's financial statements, FactSet

Structural considerations

NPI's senior secured FMB rating reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets. The A2 rating for these bonds is consistent with the two notch differential between most senior secured debt ratings and senior unsecured debt ratings of investment-grade regulated utilities operating in North America. The differential is based on our analysis of the history of regulated utility defaults, which indicates that regulated utilities have experienced lower loss given default rates (higher recovery rates) than non-financial, non-utility corporate issuers, particulary with regard to first mortgage bonds.

Rating methodology and scorecard factors

Exhibit 8

Rating Factors

Newfoundland Power Inc.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 9/30/2020		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.1x	Baa	3.8x - 4.3x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	17.8%	Baa	16% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.5%	Baa	12% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	48.6%	A	48% - 51%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2020 (L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 9

Peer Comparison Table [1]

	Newfoundland Power Inc. Baa1 Stable			FortisAlberta Inc. Baa1 Stable			Hydro One Inc. A3 Stable		
(in CAD millions)	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-18	FYE Dec-19	LTM Jun-20
Revenue	664	684	710	623	650	662	6,110	6,442	6,788
CFO Pre-W/C	117	111	125	315	353	341	1,624	1,671	1,876
Total Debt	629	638	677	2,251	2,279	2,446	13,061	13,848	14,015
CFO Pre-W/C / Debt	18.7%	17.4%	18.5%	14.0%	15.5%	13.9%	12.4%	12.1%	13.4%
CFO Pre-W/C – Dividends / Debt	14.3%	13.0%	14.3%	10.9%	12.2%	10.7%	8.2%	6.6%	9.3%
Debt / Capitalization	48.8%	48.1%	49.4%	56.2%	55.8%	56.7%	57.9%	58.8%	56.8%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Exhibit 10

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-16	Dec-17	Dec-18	Dec-19	LTM Sept-20
As Adjusted					
FFO	**104**	**109**	**106**	**113**	**106**
+/- Other	2	1	11	(3)	20
CFO Pre-WC	**107**	**110**	**117**	**111**	**125**
+/- ΔWC	12	(0)	(5)	13	15
CFO	**119**	**109**	**113**	**124**	**140**
- Div	21	38	27	28	28
- Capex	107	96	101	113	107
FCF	**(10)**	**(25)**	**(16)**	**(17)**	**5**
(CFO Pre-W/C) / Debt	18.0%	17.8%	18.7%	17.4%	18.5%
(CFO Pre-W/C - Dividends) / Debt	14.4%	11.6%	14.3%	13.0%	14.3%
FFO / Debt	17.6%	17.7%	16.9%	17.8%	15.6%
RCF / Debt	14.0%	11.5%	12.6%	13.5%	11.4%
Revenue	672	672	664	684	710
Cost of Good Sold	441	440	427	445	471
Interest Expense	36	36	37	37	37
Total Assets	1,540	1,589	1,628	1,703	1,721
Total Liabilities	1,058	1,104	1,128	1,188	1,198
Total Equity	483	485	500	515	522

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 11

Newfoundland Power Inc. Moody's - Adjusted Debt Breakdown

(In CN $ Millions)	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-19	LTM Ending Sept-20
As Reported Debt	**569.5**	**576.4**	**597.3**	**612.3**	**570.3**	**668.6**
Pensions	6.9	6.1	6.3	5.5	5.6	5.6
Hybrid Securities	8.9	8.9	8.9	8.9	8.8	0.0
Non-Standard Adjustı	0.0	2.6	2.8	2.6	52.9	2.8
Moody's - Adjusted Debt	**585.3**	**594.0**	**615.3**	**629.3**	**637.7**	**677.0**

Based on consolidated financial data of Newfoundland Power Inc. All figures are calculated using Moody's estimates and standard adjustments.
Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
NEWFOUNDLAND POWER INC.	
Outlook	Stable
Issuer Rating -Dom Curr	Baa1
First Mortgage Bonds -Dom Curr	A2
PARENT: FORTIS INC.	
Outlook	Stable
Issuer Rating -Dom Curr	Baa3
Senior Unsecured	Baa3

Source: Moody's Investors Service

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
INVESTORS SERVICE

Rating Report
Newfoundland Power Inc.

DBRS Morningstar
October 19, 2020

Contents

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
First Mortgage Bonds	A	Confirmed	Stable

Rating Update

On September 29, 2020, DBRS Limited (DBRS Morningstar) confirmed Newfoundland Power Inc.'s (Newfoundland Power or the Company) Issuer Rating and First Mortgage Bonds rating at "A." All trends are Stable. The ratings are supported by the Company's stable regulated operations, mainly consisting of electricity distribution, the reasonable regulatory regime under the Board of Commissioners of Public Utilities (PUB), and a solid financial profile.

Newfoundland Power is regulated under cost-of-service (COS) regulation by the PUB and continues to benefit from multiple regulatory deferral accounts, reducing volatility in earnings and cash flow. In January 2019, the PUB approved the Company's 2019/2020 General Rate Application (GRA), with an allowed return on equity (ROE) of 8.5% and a deemed equity component of 45.0% for 2019 to 2021.

The biggest challenge the Company faces is a potential rate shock for ratepayers from the Muskrat Falls project, an 824-megawatt (MW) hydroelectric generating facility under development by Nalcor Energy that is expected to be fully commissioned in 2021. A rate shock could severely reduce electricity volumes and affordability for Newfoundland Power's customers and negatively affect the Company's earnings and cash flow. On February 7, 2020, the PUB provided its final rate mitigation report to the Province of Newfoundland and Labrador (the Province; rated A (low) with a Negative trend by DBRS Morningstar) on potential options to mitigate the impact of the Muskrat Falls project on electricity prices, but it is currently uncertain how relief will be provided to ratepayers. DBRS Morningstar continues to monitor the situation and treats a potential rate shock as an event risk. DBRS Morningstar expects the Province to provide financial support to the ratepayers to soften the impact of a rate shock; on September 25, 2020, the Province reiterated its commitment to mitigate the risk of a rate shock associated with Muskrat Falls.

DBRS Morningstar also notes that current weak oil prices and the ongoing Coronavirus Disease (COVID-19) pandemic have negatively affected already weak provincial economic conditions. Prolonged weak economic conditions could significantly affect affordability for Newfoundland Power's customers. However, DBRS Morningstar believes that the Company's strong financial profile provides enough flexibility to absorb any short-term negative impact on cash flow to support the current ratings.

Newfoundland Power's key credit metrics remained solid for the current ratings in 2019 and for the last 12 months (LTM) ended June 30, 2020. The Company's earnings and cash flow have largely remained steady year over year, reflecting the stable nature of its operations. Newfoundland Power is expected to have moderate free cash flow deficits for the next few years. DBRS Morningstar expects the Company to manage these deficits prudently to maintain leverage in line with the regulatory capital structure, allowing key credit metrics to stay within the current rating category. A positive rating action for the Company is unlikely in the near-to-medium term because of the weaker franchise area and uncertainty regarding the rate impact from the Muskrat Falls project. Although unlikely, if ratepayers' ability to pay bills or Newfoundland Power's ability to fully pass on costs is negatively affected, the Company's ratings may be downgraded by multiple notches.

Financial Information

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
Newfoundland Power Inc.	**2020**	**2019**	**2020**	**2019**	**2018**	**2017**	**2016**	**2015**
Total debt in capital structure (%)	56.1	55.2	56.1	54.1	54.5	54.6	53.8	54.5
Cash flow/Total debt (%)	18.7	16.5	18.1	17.9	19.3	18.4	18.6	17.3
EBIT gross interest coverage (times)	2.37	2.70	2.38	2.54	2.58	2.72	3.03	3.22
(CFO+interest)/(Interest+sinking fund payment)	7.66	6.82	3.58	3.40	3.57	12.01	1.99	10.00

Issuer Description

Newfoundland Power is a regulated utility that primarily distributes but also generates and transmits electricity to approximately 269,000 customers throughout the island portion of the Province (rated A (low) with a negative trend by DBRS Morningstar). The Company is a subsidiary of Fortis Inc. (rated BBB (high) with a Positive trend by DBRS Morningstar).

Rating Considerations

Strengths

1. Stable and supportive regulatory environment

Newfoundland Power operates in a stable and supportive regulatory environment that is based on COS regulation. The PUB allows for the pass-through of purchased power costs, and a Rate Stabilization Account (RSA) is in place to absorb fluctuations in purchased power costs relating primarily to the cost of fuel oil used by Newfoundland and Labrador Hydro (NLH; rated A (low) with a Negative trend by DBRS Morningstar) to generate electricity. Furthermore, the Company also has a Weather Normalization Reserve (WNR) to stabilize earnings during extreme weather conditions.

2. Solid financial profile

Newfoundland Power has maintained a solid financial profile, underpinned by the Company's reasonable financial leverage and stable cash flow. For the LTM ended June 30, 2020, Newfoundland Power's total debt in the capital structure remained low at approximately 56.1%, while its cash flow-to-debt and EBIT interest coverage ratios remained solid at 18.1% and 2.38 times, respectively.

3. Stable customer base

Newfoundland Power has a stable customer base with power sales consisting solely of those to residential and commercial customers. As such, the Company is somewhat less sensitive to economic cycles than utilities with exposure to industrial customers, and it has relatively more stable throughputs year over year.

Challenges

1. Uncertainty about rate shock from the Muskrat Falls project

The Muskrat Falls project is an 824 MW hydroelectric generating facility developed by Nalcor (100% owned by the Province). Latest estimate for the total cost for the project has gone up to $13.1 billion from $12.7 as estimated in June 2017 and it is currently uncertain how costs for the project will be recovered from Newfoundland Power's customers; however, should upward pressure on rates affect the Company's ability to pass on costs, this would negatively affect its credit profile. Based on current projections by Nalcor Energy, rates are expected to increase to 23.10 cents per kilowatt hour (kWh) in 2022 (13.1 cents/kWh in 2020). On February 7, 2020, the PUB provided its final rate mitigation report to the Province on options to mitigate the impact of the Muskrat Falls project on electricity prices. On September 25, 2020, the Province reiterated its commitment to mitigate the risk of a rate increase associated with Muskrat Falls. The Province is currently looking at various options, including renegotiating the financial arrangement for the Muskrat Fall project with the Federal Government. The Province has estimated that approximately $725 million will be required annually to mitigate the risk of a rate increase associated with the Muskrat Falls project.

2. Weak economic outlook and limited population growth

Current low oil prices and the ongoing pandemic have put additional negative pressure on the Province's weak economic conditions that may negatively impact affordability for Newfoundland Power's customers. Additionally, electricity consumption growth in the Province is largely driven by growth in the customer base, which is dependent on population growth. Over the years, population growth in the Province has been relatively flat, limited by the Province's geographic isolation.

3. Reliance on one major power supplier

Newfoundland Power relies heavily on NLH for its power supply, sourcing approximately 93% of its power requirements from one provider. As the Province experiences relatively extreme weather, including winter storms, there have been instances in the past where infrastructure malfunctions for NLH have led to widespread blackouts. In addition, the cost of power purchased from NLH is currently largely influenced by the market price of bunker C fuel used by the Holyrood Thermal Generating Station, which has seen some volatility over the past few years. Once the Muskrat Falls project comes into service, dependency on bunker C fuel would also decrease.

Earnings and Outlook

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2020**	**2019**	**2018**	**2017**	**2016**	**2015**
Net revenues	121	121	239	239	237	232	229	231
EBITDA	80	83	159	162	160	161	169	173
EBIT	45	49	90	94	95	98	108	116
Gross interest expense	19	18	38	37	37	36	36	36
Earnings before taxes	23	29	49	54	54	54	52	50
Net income before nonrecurring items	18	23	39	43	42	42	41	39
Reported net income	18	23	39	43	42	42	41	39
Actual return on equity (%)	7.0	8.7	7.4	8.3	8.3	8.4	8.4	8.5
Regulated rate base	n/a	n/a	n/a	1,154	1,117	1,092	1,061	1,019

2019 Summary

- EBITDA was stable in 2019 when compared with 2018 and 2017, reflecting the stable business profile. The decrease from 2016 is largely because of a change in accounting policy, with the current service cost component of net benefit costs now included as an operating expense.
- EBIT decreased modestly because of higher depreciation from the growing asset base.

2020 Summary/Outlook

- EBITDA decreased for the LTM ended June 30, 2020, largely reflecting 1) the higher operating expense associated with a severe storm in January 2020; 2) the timing of purchased power costs related to wholesale electricity rate change as a result of the implementation of NLH's 2017 GRA order; and 3) lower electricity sales.
- DBRS Morningstar does not expect the ongoing pandemic to have any material impact on earnings in 2020 because the Company operates a critical infrastructure and provides an essential service.

Financial Profile

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2020**	**2019**	**2018**	**2017**	**2016**	**2015**
Net income before non-recurring items	18	23	39	43	42	42	41	39
Depreciation & amortization	35	34	70	68	65	63	61	57
Deferred income taxes and other	9	(3)	12	0	11	5	6	2
Cash flow from operations	62	53	121	111	118	110	107	98
Dividends paid	(14)	(14)	(28)	(28)	(28)	(39)	(22)	(10)
Capital expenditures	(44)	(44)	(105)	(105)	(99)	(92)	(103)	(113)
Free cash flow (bef. working cap. changes)	4	(5)	(13)	(22)	(9)	(21)	(18)	(25)
Changes in non-cash work. cap. items	(28)	(24)	9	13	(5)	(0)	12	5
Net free cash flow	(25)	(29)	(4)	(8)	(14)	(21)	(6)	(20)
Net equity change	(9)	(0)	(9)	(0)	(0)	(0)	(0)	(0)
Net debt change	48	29	28	8	15	21	7	20
Other	(0)	0	(0)	(0)	(1)	(0)	(1)	0
Change in cash	14	(0)	14	(0)	0	(0)	(0)	(0)
Total debt	669	641	669	621	612	597	576	570
Total debt in capital structure (%)	56.1	55.2	56.1	54.1	54.5	54.6	53.8	54.5
Cash flow/Total debt (%)	18.7	16.5	18.1	17.9	19.3	18.4	18.6	17.3
EBIT gross interest coverage (times)	2.37	2.70	2.38	2.54	2.58	2.72	3.03	3.22
Dividend payout ratio (%)	78.1	62.6	73.5	65.8	66.6	93.9	54.4	25.6

2019 Summary

- Newfoundland Power's key credit metrics remained relatively stable in 2019 and supportive of the "A" ratings.
- The decrease in cash flow from operations in comparison to 2018 reflects the operation of PUB-approved regulatory mechanism.
- Similar to previous years, the majority of capex in 2019 was maintenance capex.
- The Company paid dividends in accordance with its policy of maintaining the debt-to-capital in line with the regulatory capital structure as approved by the PUB for rate-setting purposes. The Company incurred a moderate net free cash flow deficit of approximately $8 million, which was funded with debt.

2020 Summary/Outlook

- Newfoundland Power's key credit metrics for the LTM ended June 30, 2020, remained relatively stable compared with 2019 and continued to support the current rating category.
- Higher cash flow from operations for the LTM ended June 30, 2020, reflects the timing of the recovered amounts deferred in its regulatory accounts.
- The PUB has approved a capital plan of $96.6 million for 2020. The Company had spent approximately $36.4 million as of June 30, 2020.
- DBRS Morningstar expects Newfoundland Power to continue to maintain its approved capital structure through dividend management and debt financing.

Long-Term Debt Maturities and Liquidity

- Newfoundland Power has a $100.0 million committed revolving unsecured credit facility expiring in August 2024 (nil outstanding as at June 30, 2020) and a $20.0 million uncommitted demand facility (nil outstanding as at June 30, 2020).
- The credit facilities contain customary covenants, including maintaining a debt-to-capitalization ratio at or below 65%. The Company was in compliance with all covenants as at June 30, 2020.

(CAD millions - as at June 30, 2020)	**2020-2021**	**2021-2022**	**2023-2024**	**Thereafter**	**Total**
First mortgage sinking fund bonds	37.2	42.0	13.6	578.5	671.3
Credit facilities (unsecured)	0.0	0.0	0.0	0.0	0.0
Demand facility (uncommitted)	0.0	0.0	0.0	0.0	0.0
Total	**37.2**	**42.0**	**13.6**	**578.5**	**671.3**

Note: Gross debt; debt issue costs not subtracted from total debt.

Hydro Ottawa Holding Inc.	12 mos. to Jun. 30			For the year ended December 31		
(CAD millions where applicable)	**2020**	**2019**	**2018**	**2017**	**2016**	**2015**
Consolidated external debt [1]	1,040	1,040	800	731	642	573
Total debt in capital structure (%) [1,2]	68.2	68.9	63.3	62.5	60.1	58.1
Cash flow/Total debt (%) [1,2]	10.2	8.8	13.8	11.2	14.2	16.0
EBIT gross interest coverage (times) [1,2]	2.64	2.34	3.60	2.22	2.96	2.82

1. Excludes nonrecourse debt. 2. Includes operating leases.

- The debt repayment schedule is modest in the near term to the medium term.

Debt Outstanding

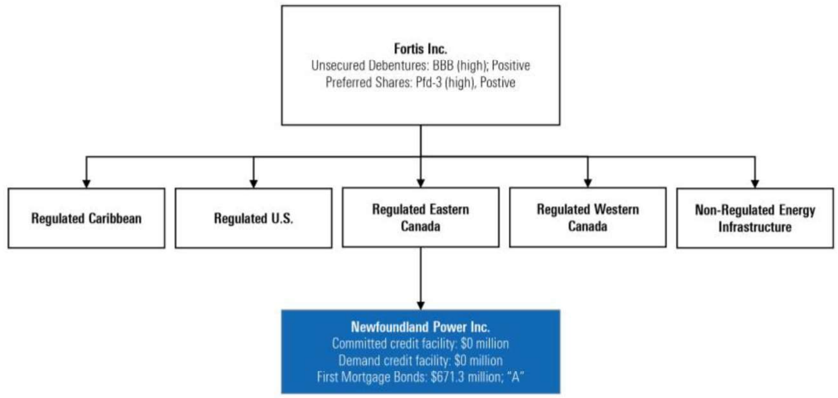
(CAD millions)		
Debt Outstanding		**December 2019**
First mortgage sinking fund bonds:		
$40 million Series AF, due 2022	10.125%	29.2
$40 million Series AG, due 2020	9.000%	30.0
$40 million Series AH, due 2026	8.900%	30.8
$50 million Series AI, due 2028	6.800%	39.5
$75 million Series AJ, due 2032	7.520%	62.3
$60 million Series AK, due 2035	5.441%	51.0
$70 million Series AL, due 2037	5.901%	60.9
$65 million Series AM, due 2039	6.606%	57.9
$70 million Series AN, due 2043	4.805%	65.8
$75 million Series AO, due 2045	4.446%	71.3
$75 million Series AP, due 2057	3.815%	72.8
		571.3
Credit & demand facilities		0.0
		571.3
Less: current portion		(36.2)
		535.1

Note: $40 million 9.00% Series AG First Mortgage Bonds, due 2020 was repaid on October 1, 2020.

- In April 2020, the Company issued $100 million in first mortgage sinking fund bonds. Net proceeds from the bonds were used to repay short-term borrowing and to refund the First Mortgage Bonds due in 2020.

- The First Mortgage Bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.
- The Company must meet an Earnings Test, whereby the net earnings are at least twice the annual interest charges on all bonds outstanding after any proposed additional bond issue. Net earnings are considered in a period of any 12 consecutive months, terminating within 24 months preceding the delivery of such additional bonds.
- The Company must also meet the Additional Property Test, whereby the additional bonds must not exceed 60% of the fair value of the additional property.
- Given the availability of funds under the credit facilities and stable cash flow from operations, the Company's liquidity remains adequate to fund both working capital requirements and cash flow deficits.

Organizational Structure



As at June 30, 2020.

Regulation

Regulatory Overview

- Newfoundland Power is regulated by the PUB, which is responsible for setting electricity rates, approving capex and deciding on the appropriate capital structure and ROE for rate-setting purposes. Rates are set based on a COS methodology.
- On January 24, 2019, the PUB issued the Order on Newfoundland Power's 2019/2020 GRA, which established the Company's allowed ROE at 8.50% and common equity at 45.00% for the 2019 through 2021 rate years. DBRS Morningstar views the capital structure as favourable and a positive for the Company's credit profile.
    - The order didn't make any changes in the deferral accounts.
    - The order did not lead to any increase in electricity rates.
- Effective October 1, 2019, PUB approved an effective increase of 6.4% in electricity rates charges to customers primarily due to an increase in the wholesale electricity rate charged to the Company by NLH as a result of NLH's 2017 GRA.
- In February 2020, the PUB approved Newfoundland Power's 2020 capital plan of $96.6 million.

Regulator-Approved Accounts

Deferral accounts are used to smooth the impact of realized expenses and events differing from forecast.

- **Weather Normalization Reserve (WNR):** The WNR reduces earnings volatility by adjusting electricity purchases and sales to eliminate the variance between normal weather conditions, based on long-term averages, and actual realized weather conditions.
- **Rate Stabilization Account (RSA):** The RSA allows Newfoundland Power to pass through costs related to changes in the price and quantity of fuel charged by NLH to the end consumer. On July 1 of each year, customer rates are recalculated to amortize the balance in the RSA as of March 31 of the current year over the subsequent 12 months. In the absence of rate regulation, these transactions would be

accounted for in a similar manner; however, the amount and timing of the recovery would not be subject to PUB approval. To the extent that actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. Effective January 1, 2008, the PUB ordered that variations in purchased power expense caused by differences between the actual unit cost of energy and the cost reflected in customer rates be recovered from (refunded to) customers through the RSA.

- **Demand Management Incentive Account (DMIA):** Through the DMIA, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1.0% of demand costs reflected in customer rates. Balances in this account are recorded as a regulatory asset or regulatory liability on Newfoundland Power's balance sheet. The final balance of regulatory assets and liabilities is determined by the PUB, which considers the merits of the Company's conservation efforts and demand-management activities.
- **Pension Expense Variance Deferral Account (PEVDA):** The PEVDA is used when differences exist between the defined benefit pension expense calculated in accordance with designated accounting standards and the pension expense approved by the PUB for rate-setting purposes.
- **Other Post-Employment Benefits (OPEB):** The OPEB cost deferral account is used when differences exist between the OPEB expenses calculated in accordance with designated accounting standards and the OPEB expenses approved by the PUB for rate-setting purposes.
- **Excess Earnings Account (EEA):** Any earnings that exceed the upper limit of the allowed range of return on rate base set by the PUB are credited to the Company's EEA. Amounts credited to the EEA are subject to further order of the PUB.

Newfoundland Power Inc.							
(CAD millions)	June 30	Dec. 31	Dec. 31		June 30	Dec. 31	Dec. 31
Assets	**2020**	**2019**	**2018**	**Liabilities & Equity**	**2020**	**2019**	**2018**
Cash & equivalents	14	0	0	S.T. borrowings	0	1	0
Accounts receivable	74	84	84	Accounts payable	41	90	85
Regulatory assets	12	17	10	Current portion L.T.D.	37	87	44
Prepaid expenses & other	2	6	4	Other current liab.	18	21	11
Total Current Assets	**102**	**106**	**99**	**Total Current Liab.**	**97**	**200**	**139**
Net fixed assets	1,215	1,204	1,159	Long-term debt	631	533	569
Future income tax assets	224	220	213	Provisions	270	270	243
Intangibles	28	28	25	Deferred income taxes	172	173	161
Regulatory assets	116	127	123	Other L.T. liab.	14	1	5
Pensions & Other	21	18	10	Preferred shares	0	9	9
				Common equity	522	518	503
Total Assets	**1,706**	**1,703**	**1,628**	**Total Liab. & SE**	**1,706**	**1,703**	**1,628**

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
Balance Sheet & Liquidity & Capital Ratios	**2020**	**2019**	**2020**	**2019**	**2018**	**2017**	**2016**	**2015**
Current ratio	1.06	0.68	1.06	0.53	0.71	0.82	0.58	0.73
Total debt in capital structure (%)	56.1	55.2	56.1	54.1	54.5	54.6	53.8	54.5
Cash flow/Total debt (%)	18.7	16.5	18.1	17.9	19.3	18.4	18.6	17.3
(Cash flow-dividends)/Capex (times)	1.08	0.89	0.88	0.79	0.91	0.77	0.83	0.78
Dividend payout ratio (%)	78.1	62.6	73.5	65.8	66.6	93.9	54.4	25.6
Coverage Ratios (times)								
EBIT gross interest coverage	2.37	2.70	2.38	2.54	2.58	2.72	3.03	3.22
EBITDA gross interest coverage	4.25	4.54	4.23	4.38	4.36	4.47	4.72	4.79
Fixed-charges coverage	2.31	2.64	2.33	2.49	2.53	2.66	2.96	3.15
Profitability Ratios (%)								
EBITDA margin	65.8	68.2	66.6	67.8	67.5	69.3	73.7	75.0
EBIT margin	36.8	40.6	37.5	39.4	40.0	42.1	47.2	50.4
Profit margin	15.2	18.6	16.2	17.9	17.6	17.9	17.7	17.0
Return on equity	7.0	8.7	7.4	8.3	8.3	8.4	8.4	8.5
Return on capital	5.4	6.2	5.5	6.0	6.0	6.1	6.1	6.3

Operating Statistics

Operating Statistics	For the year ended December 31					
Electricity sales - breakdown (GWh)	**2019**	**2018**	**2017**	**2016**	**2015**	**2014**
Residential	3,560	3,593	3,645	3,655	3,655	3,613
General service	2,287	2,283	2,277	2,295	2,302	2,286
Total sales	5,847	5,876	5,922	5,950	5,957	5,899
Growth in volume throughputs (%)	-0.5	-0.8	-0.5	-0.1	1.0	2.4
Customers						
Residential	234,132	233,104	231,639	229,815	227,455	224,824
Commercial	34,913	34,891	34,811	34,591	34,319	34,055
Total	269,045	267,995	266,450	264,406	261,774	258,879
Energy generated and purchased (GWh)						
Energy generated	431	435	437	427	432	430
Energy purchased	5,742	5,769	5,829	5,868	5,877	5,817
Energy generated + purchased	6,173	6,204	6,266	6,295	6,309	6,247
Less: transmission losses + internal use	327	328	343	345	353	348
Total sales	5,847	5,876	5,923	5,950	5,956	5,899
System losses and internal use (%)	5.6	5.6	5.8	5.8	5.9	5.9
Installed generation capacity (MW)						
Hydroelectric	97	97	97	97	97	97
Gas turbine	37	37	37	37	37	37
Diesel	5	5	5	5	5	5
Total	139	139	139	139	139	139
Native peak demand (MW)	1,440	1,385	1,446	1,381	1,382	1,343
Rate base (CAD millions)	1,154	1,117	1,092	1,061	1,019	965
Growth in rate base (%)	3	2	3	4	6	9

Rating History

	Current	2019	2018	2017	2016	2015
Issuer Rating	A	A	A	A	A	A
First Mortgage Bonds	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable	n/a	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, September 27, 2019.

Related Research

- "DBRS Morningstar Assigns Rating of "A" with a Stable Trend to Newfoundland Power Inc.'s $100 Million First Mortgage Sinking Fund Bonds," April 20, 2020.
- "DBRS Morningstar Discontinues Rating on Newfoundland Power Inc.'s Preferred Shares," February 10, 2020.
- "DBRS Morningstar Notes Newfoundland Power Inc.'s Announced Redemption of Preference Shares," January 3, 2020.

Previous Report

- Newfoundland Power Inc.: Rating Report, October 7, 2019.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrsmorningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

About DBRS Morningstar

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On July 2, 2019, Morningstar, Inc. completed its acquisition of DBRS. Combining DBRS' strong market presence in Canada, the U.S., and Europe with Morningstar Credit Ratings' U.S. footprint has expanded global asset class coverage and provided investors with an enhanced platform featuring thought leadership, analysis, and research. DBRS and Morningstar Credit Ratings are committed to empowering investor success, serving the market through leading-edge technology and raising the bar for the industry.

Together as DBRS Morningstar, we are the world's fourth-largest credit ratings agency and a market leader in Canada, the U.S., and Europe in multiple asset classes. We rate more than 2,600 issuers and 54,000 securities worldwide and are driven to bring more clarity, diversity, and responsiveness to the ratings process. Our approach and size provide the agility to respond to customers' needs, while being large enough to provide the necessary expertise and resources.

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Newfoundland Power Inc.

Comparative Financial Forecasts
2022 - 2023
Statements of Income
($000s)

		2022		2023	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Revenue from rates	711,562	715,364	708,398	712,803
2	Transfers from (to) the RSA	(17,328)	1,172	(22,035)	6,401
3		694,234	716,536	686,363	719,204
4					
5	Purchased power expense	465,610	464,811	461,686	459,924
6	Demand management incentive account adjustments	(1,811)	-	(2,079)	-
7		463,799	464,811	459,607	459,924
8					
9	Contribution	230,435	251,725	226,756	259,280
10					
11	Other revenue[1]	4,746	5,924	4,679	6,473
12					
13	Other expenses:				
14	Operating expenses[2]	67,347	67,495	69,736	73,226
15	Employee future benefit costs[3]	8,745	8,745	6,159	2,771
16	Deferred cost recoveries and amortizations	-	(892)	-	444
17	Depreciation[4]	70,424	70,956	74,745	75,252
18	Finance charges[5]	34,605	34,712	32,935	33,074
19		181,121	181,016	183,575	184,767
20					
21	Income before income taxes	54,060	76,633	47,860	80,986
22	Income taxes[6]	15,384	22,154	13,294	24,198
23					
24	Earnings applicable to common shares[6]	38,676	54,479	34,566	56,788
25					
26	**Rate of Return and Credit Metrics**				
27	Rate of Return on Rate Base (%)	5.90	7.19	5.23	6.97
28	Regulated Return on Book Equity (%)	7.16	9.80	6.34	9.80
29	Interest Coverage (times)	2.2	2.7	2.0	2.9
30	CFO Pre-W/C + Interest / Interest (times)	4.7	4.5	5.0	4.9
31	CFO Pre-W/C / Debt (%)	18.7	17.8	19.2	18.4

[1] Shown after reclassification for other contract costs and equity portion of AFUDC. Other revenue for proposed excludes interest on RSA.

[2] Shown after adjustment for non-regulated expenses and reclassification of other contract costs and current portion of employee future benefit costs.

[3] Shown after reclassification of current portion of employee future benefit costs.

[4] Shown after reclassification of tax on cost of removal.

[5] Shown after reclassification of equity portion of AFUDC.

[6] Shown after adjustment for non-regulated expenses and reclassification of tax on cost of removal.

Newfoundland Power Inc.

Comparative Financial Forecasts
2022 - 2023
Statements of Retained Earnings
($000s)

		2022		2023	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Balance - Beginning	465,487	465,486	473,541	506,165
2	Net income for the period	36,327	52,130	32,073	54,295
3	Allocation of Part VI.1 tax	624	624	624	624
4		502,438	518,240	506,238	561,084
5					
6	Dividends				
7	Common shares	28,897	12,075	29,310	48,918
8					
9	Balance - End of Period	473,541	506,165	476,928	512,166

Newfoundland Power Inc.

Comparative Financial Forecasts
2022 - 2023
Balance Sheets
($000s)

	2022		2023	
	Existing	Proposed	Existing	Proposed
Assets				
Current Assets				
Accounts receivable	85,681	85,657	79,999	79,599
Materials and supplies	1,775	1,775	1,805	1,805
Prepaid expenses	2,625	2,625	2,669	2,669
Regulatory assets	(18,943)	7,284	(19,449)	7,297
	71,138	97,341	65,024	91,370
Property, plant and equipment	1,326,460	1,327,236	1,381,735	1,383,373
Intangible assets	57,193	57,193	61,893	61,983
Regulatory assets	305,866	325,435	301,790	325,258
Defined benefit pension plans	42,344	42,344	51,258	51,258
Other assets	2,201	2,201	2,225	2,225
	1,805,202	1,851,750	1,863,925	1,915,467
Liabilities and shareholder's equity				
Current Liabilities				
Accounts payable and accrued charges	85,886	86,533	92,024	92,934
Interest payable	7,153	7,153	7,070	7,070
Defined benefit pension plans	227	227	221	221
Other post employment benefits	3,922	3,922	4,174	4,174
Current instalments of long-term debt	7,550	7,550	7,550	7,550
	104,738	105,385	111,039	111,949
Regulatory liabilities	199,987	202,744	213,169	218,729
Defined benefit pension plans	5,402	5,402	5,544	5,544
Other post employment benefits	94,508	94,508	96,307	96,307
Other liabilities	1,212	1,212	1,212	1,212
Deferred income taxes	176,163	176,075	184,812	185,282
Long-term debt	679,330	689,938	704,593	713,957
Shareholder's equity				
Common shares	70,321	70,321	70,321	70,321
Retained earnings	473,541	506,165	476,928	512,166
	543,862	576,486	547,249	582,487
	1,805,202	1,851,750	1,863,925	1,915,467

Newfoundland Power Inc.

Comparative Financial Forecasts
2022 - 2023
Statements of Cash Flows
($000s)

		2022		2023	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Operating Activities**				
2	Net Earnings	36,327	52,130	32,073	54,295
3					
4	**Items Not Affecting Cash:**				
5	Depreciation of property, plant and equipment	72,771	74,112	75,591	76,937
6	Amortization of intangible assets and other	4,565	4,565	6,337	6,342
7	Change in long-term regulatory assets and liabilities	20,419	(1,530)	22,740	(5,231)
8	Deferred income taxes	224	136	8,649	9,207
9	Employee future benefits	(3,772)	(3,772)	(6,695)	(6,695)
10	Other	(250)	(250)	(709)	(710)
11		130,284	125,391	137,986	134,145
12					
13	Change in working capital	(2,381)	(24,916)	(6,717)	18,078
14		127,903	100,475	131,269	152,223
15					
16	**Investing Activities**				
17	Capital expenditures	(97,650)	(97,651)	(118,691)	(118,700)
18	Intangible asset expenditures	(20,670)	(20,670)	(10,854)	(10,949)
19	Contribution from customers and security deposits	2,500	2,500	2,500	2,500
20	Other	(7)	(7)	(6)	(6)
21		(115,827)	(115,828)	(127,051)	(127,155)
22					
23	**Financing Activities**				
24	Net (repayment) proceeds of committed credit facility	(21,829)	(11,222)	32,642	31,400
25	Proceeds from long-term debt	75,000	75,000	-	-
26	Repayment of long-term debt	(35,950)	(35,950)	(7,550)	(7,550)
27	Payment of debt financing costs	(400)	(400)	-	-
28	Dividends				
29	Common shares	(28,897)	(12,075)	(29,310)	(48,918)
30		(12,076)	15,353	(4,218)	(25,068)
31					
32	**Change in Cash**	-	-	-	-
33	**Cash, Beginning of Year**	-	-	-	-
34	**Cash, End of Year**	-	-	-	-

Newfoundland Power Inc.

Comparative Financial Forecasts
2022 - 2023
Average Rate Base[1]
($000s)

	2022		2023	
	Existing	Proposed	Existing	Proposed
Plant Investment	1,209,201	1,208,936	1,261,498	1,260,763
Additions to Rate Base				
Defined Benefit Pension Costs	91,526	91,526	98,201	98,201
Deferred Credit Facility Costs	24	16	10	-
Cost Recovery Deferral - Hearing Costs	-	247	-	371
Cost Recovery Deferral - Conservation	17,841	17,939	18,343	18,744
Cost Recovery Deferral - Electrification	935	1,944	935	4,180
Cost Recovery Deferral - 2022 Revenue Shortfall	-	312	-	468
Demand Management Incentive Account	1,268	634	1,361	-
Customer Finance Programs	2,166	2,166	2,202	2,202
	113,760	114,784	121,052	124,166
Deductions from Rate Base				
Other Post Employment Benefits	74,950	74,950	80,572	80,572
Customer Security Deposits	1,212	1,212	1,212	1,212
Accrued Pension Obligation	5,430	5,430	5,578	5,578
Accumulated Deferred Income Taxes	15,997	15,916	23,784	23,867
Weather Normalization Account	1,958	1,958	-	-
	99,547	99,466	111,146	111,229
Average Rate Base Before Allowances	1,223,414	1,224,254	1,271,404	1,273,700
Cash Working Capital Allowance	10,326	6,548	10,096	6,800
Materials and Supplies Allowance	8,218	8,756	8,358	8,905
Average Rate Base at Year End	1,241,958	1,239,558	1,289,858	1,289,405

[1] All amounts shown are averages.

Newfoundland Power Inc.

Comparative Financial Forecasts
2022 - 2023
Weighted Average Cost of Capital
($000s)

		2022		2023	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Average Capitalization**				
2	Debt	678,353	683,657	699,501	709,487
3	Common Equity	539,835	556,147	545,556	579,487
4		1,218,188	1,239,804	1,245,057	1,288,974
5					
6	**Average Capital Structure (%)**				
7	Debt	55.69	55.14	56.18	55.04
8	Common Equity	44.31	44.86	43.82	44.96
9		100.00	100.00	100.00	100.00
10					
11	**Cost of Capital (%)**				
12	Debt	5.10	5.07	4.71	4.66
13	Common Equity	7.16	9.80	6.34	9.80
14					
15					
16	**Weighted Average Cost of Capital (%)**				
17	Debt	2.84	2.80	2.64	2.56
18	Common Equity	3.17	4.39	2.78	4.41
19		6.01	7.19	5.42	6.97

Newfoundland Power Inc.

Comparative Financial Forecasts
2022 - 2023
Rate of Return on Rate Base
($000s)

		2022		2023	
		Existing	Proposed	Existing	Proposed
1	Regulated Return on Equity	38,676	54,479	34,566	56,788
2					
3	Finance Charges				
4	Interest on Long-Term Debt	36,005	36,005	34,945	34,945
5	Other Interest	328	435	752	892
6	Amortization of Bond Issue Expenses	197	197	183	183
7	AFUDC	(1,943)	(1,943)	(2,963)	(2,964)
8		34,587	34,694	32,917	33,056
9					
10	Return on Rate Base	73,263	89,173	67,483	89,844
11					
12	Average Rate Base	1,241,958	1,239,558	1,289,858	1,289,405
13					
14	Rate of Return on Rate Base (%)	5.90	7.19	5.23	6.97

Newfoundland Power Inc.

Financial Performance
2022P - 2023P
Inputs and Assumptions

Energy Forecasts: Energy forecasts are based on economic indicators taken from the Conference Board of Canada Economic Forecast, dated February 24, 2021.

Revenue Forecast: The revenue forecast is based on the Customer, Energy and Demand forecast dated May 2021.

Forecast revenue based on Existing Rates for 2022 through 2023 reflects: (i) recovery through the RSA of amounts associated with the Energy Supply Cost Variance Adjustment Clause; (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs; (iii) recovery through the RSA of amounts associated with the July 1, 2017 Hydro supply cost rate increase; (iv) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (v) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 13 (2013), P.U. 18 (2015), P.U. 23 (2017), P.U. 20 (2018), P.U. 2 (2019) and P.U. 31 (2019). Forecast revenue for 2022 and 2023 reflect recovery through the RSA of certain costs related to the implementation of the Electrification program portfolio as proposed in the Application.

Purchased Power Expense: Purchased power expense reflects Newfoundland & Labrador Hydro's rates approved by the Board effective October 1, 2019 and the Customer, Energy and Demand Forecast dated May 12, 2021.

Purchased power expense reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007). This mechanism provides for recovery of demand costs that are in excess of unit demand costs included in the most recent test year.

Variances in demand costs under the proposed forecasts are reflected in the 2022 and 2023 revenue requirements.

Employee Future Benefit Costs: Pension funding is based on the actuarial valuation dated as at December 31, 2019.

Pension discount rate is 2.60% for 2022 through 2023.

Expected return on pension plan assets is 4.50% for 2022 through 2023.

OPEBs discount rate is 2.70% for 2022 through 2023.

Cost Recovery Deferrals: The 2022 and 2023 forecasts include the amorization over a 7-year period of certain conservation program costs deferred prior to December 31, 2020.

The 2022 and 2023 forecasts include the deferred recovery over a 10-year period of certain conservation and electrification program costs as reflected in the Application.

The 2022 and 2023 forecasts include the deferred recovery over a 34-month period of $1.0 million in external costs related to the *2022/2023 General Rate Application* beginning March 1, 2022.

The 2022 and 2023 forecasts include the amortization beginning March 1, 2022, of a $1.3 million revenue shortfall related to a March 1, 2022 rate implementation date.

Newfoundland Power Inc.

Financial Performance
2022P - 2023P
Inputs and Assumptions

Depreciation Rates: Depreciation rates are based on the *2019 Depreciation Study.*

Operating Costs: The operating forecast for 2022 and 2023 reflects the most recent management estimates. Operating forecasts for 2022 and 2023 reflect projected increases of 3.00% in 2022 and 2.85% in 2023 for labour and non-labour increases based upon the GDP deflator.

Capital Expenditure: Capital Expenditures for 2022 and 2023 are based on the *2022 Capital Budget Application* adjusted for known carryovers.

Short-Term Interest Rates: Average short-term interest rates are forecast to be 1.36% for 2022 and 1.70% for 2023.

Long-Term Debt: A $75.0 million long-term debt issue is forecast to be completed in March 2022. The debt is forecast for 30 years at a coupon rate of 4.25%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

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

Income Tax: Income tax expense reflects a statutory income tax rate of 30% for 2022 through 2023.

Newfoundland Power Inc.

Forecast Average Rate Base[1]
2022 - 2023
($000s)

	2022	2023
Plant Investment	1,208,936	1,260,763
Additions to Rate Base		
Defined Benefit Pension Costs	91,526	98,201
Deferred Credit Facility Costs	16	-
Cost Recovery Deferral - Hearing Costs	247	371
Cost Recovery Deferral - Conservation	17,939	18,744
Cost Recovery Deferral - Electrification	1,944	4,180
Cost Recovery Deferral - 2022 Revenue Shortfall	312	468
Demand Management Incentive Account	634	-
Customer Finance Programs	2,166	2,202
	114,784	124,166
Deductions from Rate Base		
Other Post Employment Benefits	74,950	80,572
Customer Security Deposits	1,212	1,212
Accrued Pension Obligation	5,430	5,578
Accumulated Deferred Income Taxes	15,916	23,867
Weather Normalization Account	1,958	-
	99,466	111,229
Average Rate Base Before Allowances	1,224,254	1,273,700
Cash Working Capital Allowance	6,548	6,800
Materials and Supplies Allowance	8,756	8,905
Average Rate Base at Year End	1,239,558	1,289,405

[1] Based upon proposed rates. All amounts shown are averages.

Newfoundland Power Inc.

2022 Revenue Requirement[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	465,610	(799)	464,811
3	Operating Costs	67,347	148	67,495
4	Employee Future Benefit Costs	8,745	-	8,745
5	Deferred Cost Recoveries and Amortizations	-	(892)	(892)
6	Depreciation[2]	70,424	532	70,956
7	Income Taxes	15,384	6,770	22,154
8		627,510	5,759	633,269
9				
10	**Return on Rate Base**	73,263	15,910	89,173
11				
12	**2022 Revenue Requirement**	700,773	21,669	722,442
13				
14	**Adjustments**			
15	Other Revenue[3]	(4,746)	(1,178)	(5,924)
16	Interest on Security Deposits	18	-	18
17	Energy Supply Cost Variance Adjustments	24,348	(19,477)	4,871
18	Demand Management Incentive Adjustments	(1,811)	1,811	-
19	Other Transfers to RSA	(7,020)	977	(6,043)
20		10,789	(17,867)	(7,078)
21				
22	**2022 Revenue Requirement from Rates[4]**	711,562	3,802	715,364

[1] See *Volume 1, Application, Company Evidence and Exhibits, Section 4.3: 2022 and 2023 Revenue Requirements* for a summary of the Company's 2022 revenue requirement proposals.

[2] The increase in depreciation expense is related to the implementation of depreciation rates outlined in the *2019 Depreciation Study. See Volume 1, Application, Company Evidence and Exhibits, Section 3.2.3: Depreciation.*

[3] Excludes equity component of capitalized interest. Other revenue for proposed also excludes interest on the RSA.

[4] Existing revenue requirement for 2022 excludes price elasticity impacts related to revenue of $479,000. The required revenue increase of $4,281,000 in 2022 (see Exhibit 9, page 1 of 2, line 1, column E) is comprised of $3,802,000 and price elasticity impacts related to revenue of $479,000 (see Exhibit 9, page 1 of 2, line 1, column D).

Newfoundland Power Inc.

2023 Revenue Requirement[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	461,686	(1,762)	459,924
3	Operating Costs	69,736	3,490	73,226
4	Employee Future Benefit Costs	6,159	(3,388)	2,771
5	Deferred Cost Recoveries and Amortizations	-	444	444
6	Depreciation[2]	74,745	507	75,252
7	Income Taxes	13,294	10,904	24,198
8		625,620	10,195	635,815
9				
10	**Return on Rate Base**	67,483	22,361	89,844
11				
12	**2023 Revenue Requirement**	693,103	32,556	725,659
13				
14	**Adjustments**			
15	Other Revenue[3]	(4,679)	(1,794)	(6,473)
16	Interest on Security Deposits	18	-	18
17	Energy Supply Cost Variance Adjustments	26,665	(26,665)	-
18	Demand Management Incentive Adjustments	(2,079)	2,079	-
19	Other Transfers to RSA	(4,630)	(1,771)	(6,401)
20		15,295	(28,151)	(12,856)
21				
22	**2023 Revenue Requirement from Rates**[4]	708,398	4,405	712,803

[1] See *Volume 1, Application, Company Evidence and Exhibits, Section 4.3: 2022 and 2023 Revenue Requirements* for a summary of the Company's 2023 revenue requirement proposals.

[2] The increase in depreciation expense is related to the implementation of depreciation rates outlined in the *2019 Depreciation Study. See Volume 1, Application, Company Evidence and Exhibits, Section 3.2.3: Depreciation.*

[3] Excludes equity component of capitalized interest. Other revenue for proposed also excludes interest on the RSA.

[4] Existing revenue requirement for 2023 excludes price elasticity impacts related to revenue of $1,075,000. The required revenue increase of $5,480,000 in 2023 (see Exhibit 9, page 2 of 2, line 1, column E) is comprised of $4,405,000 and price elasticity impacts related to revenue of $1,075,000 (see Exhibit 9, page 2 of 2, line 1, column D).

Newfoundland Power Inc.

2022 Return on Rate Base
($000s)

		Existing	Changes		Proposed
1					
2	**Average Capitalization**				
3	Debt	678,353	5,304		683,657
4	Common Equity	539,835	16,312	1	556,147
5		1,218,188	21,616		1,239,804
6					
7	**Average Capital Structure**				
8	Debt	55.69	-0.55		55.14
9	Common Equity	44.31	0.55	1	44.86
10		100.00	0.00		100.00
11					
12	**Cost of Capital**				
13	Debt	5.10	-0.03		5.07
14	Common Equity	7.16	2.64	1	9.80
15					
16	**Weighted Average Cost of Capital**				
17	Debt	2.84	-0.04		2.80
18	Common Equity	3.17	1.22		4.39
19		6.01	1.18		7.19
20					
21	**Return on Rate Base**[2]				
22	Return on Debt	34,587	107		34,694
23	Return on Common Equity	38,676	15,803	1	54,479
24		73,263	15,910		89,173

[1] Reflects the Company's proposed return on common equity of 9.8 percent in 2022.
[2] Total financing costs for 2022 forecast are as follows ($000s):

Return on debt from above	34,694
Add: Interest on security deposits	18
Finance Charges, Exhibit 5, Page 1, Line 18	34,712

Newfoundland Power Inc.

2023 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	699,501	9,986	709,487
4	Common Equity	545,556	33,931 [1]	579,487
5		1,245,057	43,917	1,288,974
6				
7	**Average Capital Structure**			
8	Debt	56.18	-1.14	55.04
9	Common Equity	43.82	1.14 [1]	44.96
10		100.00	0.00	100.00
11				
12	**Cost of Capital**			
13	Debt	4.71	-0.05	4.66
14	Common Equity	6.34	3.46 [1]	9.80
15				
16	**Weighted Average Cost of Capital**			
17	Debt	2.64	-0.08	2.56
18	Common Equity	2.78	1.63	4.41
19		5.42	1.55	6.97
20				
21	**Return on Rate Base**[2]			
22	Return on Debt	32,917	139	33,056
23	Return on Common Equity	34,566	22,222 [1]	56,788
24		67,483	22,361	89,844

[1] Reflects the Company's proposed return on common equity of 9.8 percent in 2023.

[2] Total financing costs for 2023 forecast are as follows ($000s):

Return on debt from above	33,056
Add: Interest on security deposits	18
Finance Charges, Exhibit 5, Page 1, Line 18	33,074

Newfoundland Power Inc.

2022 Revenue Requirement to Revenue from Rates Reconciliation
($000s)

		Existing	Proposed	Difference	Price Elasticity[1]	Proposed Increase[2]
		A	B	C	D	E
1	**Revenue From Rates**	711,562[3]	715,364[4]	3,802[5]	479	4,281
2						
3	**RSA Charges**[6]	2,462	2,460	(2)	2	-
4						
5	**MTA Charges**	17,111	17,203	92	12	104
6						
7	**Total**	731,135	735,027	3,892	493	4,385

[1] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.

[2] The difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C + Column D).

[3] 2022 revenue from existing rates from *Exhibit 7,* page 1 of 2.

[4] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from *Exhibit 7,* page 1 of 2. Revenue from proposed rates reflects revenue from existing rates for January to February plus revenue from proposed rates for March to December of 2022.

[5] *Exhibit 7* of the Application indicates a required increase in 2022 revenue from rates of $3,802,000 net of elasticity effects.

[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective October 1, 2019.

Newfoundland Power Inc.

2023 Revenue Requirement to Revenue from Rates Reconciliation
($000s)

		Existing	Proposed	Difference	Price Elasticity[1]	Proposed Increase[2]
		A	B	C	D	E
1	**Revenue From Rates**	708,398[3]	712,803[4]	4,405[5]	1,075	5,480
2						
3	**RSA Charges**[6]	2,444	2,438	(6)	6	-
4						
5	**MTA Charges**	17,005	17,109	104	27	131
6						
7	**Total**	727,847	732,350	4,503	1,108	5,611[7]

[1] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.
[2] The difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C + Column D).
[3] 2023 revenue from existing rates from *Exhibit 7,* page 2 of 2.
[4] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from *Exhibit 7,* page 2 of 2.
[5] *Exhibit 7* of the Application indicates a required increase in 2023 revenue from rates of $4,405,000 net of elasticity effects.
[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective October 1, 2019.
[7] See *Exhibit 10,* Column E.

Newfoundland Power Inc.

2023 Average Customer Billing Impacts
($000s)

Forecast Impacts by Rate Class Under Existing and Proposed Rates
(includes October 1, 2019 RSA and MTA)

	Category	Existing Rates	Adjustment Due to Price Elasticity	Adjusted Existing Rates	Proposed Rates	Increase	Rate Increase
1		(A) [1]	(B) [2]	(C) [3]	(D) [4]	(E) [5]	(F) [6]
2							
3	1.1 Domestic	454,445	(1,074)	453,371	456,870	3,499	0.8%
4	1.1S Domestic Seasonal	1,790	-	1,790	1,804	14	0.8%
5	Total Domestic	456,235	(1,074)	455,161	458,674	3,513	0.8%
6							
7	2.1 General Service 0-100 kW	101,045	(30)	101,015	101,794	779	0.8%
8	2.3 General Service 110-1000 kVA	111,940	-	111,940	112,805	865	0.8%
9	2.4 General Service over 1000 kVA	38,758	-	38,758	39,058	300	0.8%
10	Total General Service	251,743	(30)	251,713	253,657	1,944	0.8%
11							
12	4.1 Street and Area Lighting	17,024	-	17,024	17,156	132	0.8%
13	Forfeited Discounts	2,845	(4)	2,841	2,863	22	0.8%
14							
15	**Total**	727,847	(1,108)	726,739	732,350	5,611	0.8%

[1] Column A is the forecast revenue plus RSA and MTA under existing rates, based on the 2023 test year sales forecast without elasticity impacts. See *Exhibit 9* , page 2 of 2, Column A.

[2] Column B is the elasticity impact on existing customer billings reflecting a 0.8% average increase in customer rates.

[3] Column C is the forecast customer billings under existing rates including elasticity impacts (Column A + Column B).

[4] Column D is the forecast customer billings under proposed rates including elasticity impacts. See *Exhibit 9* , page 2 of 2, Column B.

[5] Column E is the difference between forecast under proposed rates and that under existing rates adjusted for elasticity (Column D - Column C).

[6] Column F is the forecast rate increase (Column E / Column C).

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	October 1, 2019 Existing Rates	March 1, 2022 Proposed Rates
Domestic - Rate #1.1		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$15.97/month	$16.10/month
Exceeding 200 Amp Service	$20.97/month	$21.10/month
Energy Charge - All kilowatt hours	12.203 ¢/kWh	12.298 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$15.97/month	$16.10/month
Exceeding 200 Amp Service	$20.97/month	$21.10/month
Prompt Payment Discount	1.5%	1.5%
Domestic - Rate #1.1S		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$15.97/month	$16.10/month
Exceeding 200 Amp Service	$20.97/month	$21.10/month
Energy Charge		
Winter Seasonal	13.156 ¢/kWh	13.251 ¢/kWh
Non-Winter Seasonal	10.906 ¢/kWh	11.001 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$15.97/month	$16.10/month
Exceeding 200 Amp Service	$20.97/month	$21.10/month
Prompt Payment Discount	1.5%	1.5%

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	October 1, 2019 Existing Rates	March 1, 2022 Proposed Rates
G.S. 0-100 kW (110 kVA) - Rate #2.1		
Basic Customer Charge		
Unmetered	$12.13/month	$12.30/month
Single Phase	$20.13/month	$20.30/month
Three Phase	$32.13/month	$32.30/month
Demand Charge Regular	$9.79/kW - winter $7.29/kW - other	$9.85/kW - winter $7.35/kW - other
Energy Charge		
First 3,500 kilowatt-hours	12.062 ¢/kWh	12.155 ¢/kWh
All excess kilowatt-hours	9.074 ¢/kWh	9.145 ¢/kWh
Maximum Monthly Charge	20.934 ¢/kWh + B.C.C.	21.096 ¢/kWh + B.C.C.
Minimum Monthly Charge		
Unmetered	$12.13/month	$12.30/month
Single Phase	$20.13/month	$20.30/month
Three Phase	$32.13/month	$32.30/month
Prompt Payment Discount	1.5%	1.5%
G.S. 110-1000 kVA - Rate #2.3		
Basic Customer Charge	$49.38/month	$49.76/month
Demand Charge	$8.21/kVA-winter $5.71/kVA-other	$8.27/kVA-winter $5.77/kVA-other
Energy Charge		
First 150 kWh per kVA of demand (max. 50,000)	10.270 ¢/kWh	10.349 ¢/kWh
All Excess kWh	8.292 ¢/kWh	8.356 ¢/kWh
Maximum Monthly Charge	20.934 ¢/kWh + B.C.C.	21.096 ¢/kWh + B.C.C.
Minimum Monthly Charge	$49.38/month	$49.76/month
Prompt Payment Discount	1.5%	1.5%

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	October 1, 2019 Existing Rates	March 1, 2022 Proposed Rates
G.S. 1000 kVA and Over - Rate #2.4		
Basic Customer Charge	\$86.05/month	\$86.71/month
Demand Charge	\$7.88/kVA-winter \$5.38/kVA-other	\$7.92/kVA-winter \$5.42/kVA-other
Energy Charge		
First 75,000 kWh	9.905 ¢/kWh	9.981 ¢/kWh
All Excess kWh	8.211 ¢/kWh	8.275 ¢/kWh
Maximum Monthly Charge	20.934 ¢/kWh + B.C.C.	21.096 ¢/kWh + B.C.C.
Minimum Monthly Charge	\$86.05/month	\$86.71/month
Prompt Payment Discount	1.5%	1.5%

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

Street and Area Lighting Rates

		October 1, 2019 Existing Rates	March 1, 2022 Proposed Rates
Fixtures			
Sentinel/Standard			
High Pressure Sodium	100W	$17.89	$18.05
	150W	22.02	22.44
	250W	30.55	31.84
	400W	41.87	44.65
Light Emitting Diode	LED 100	$16.20	$16.18
	LED 150	17.70	18.16
	LED 250	22.68	21.97
	LED 400	25.71	25.29
Post Top			
High Pressure Sodium	100W	$19.30	$19.28
Poles			
Wood		$6.27	$6.49
30' Concrete or Metal, direct buried		8.95	9.06
45' Concrete or Metal, direct buried		14.65	15.04
25' Concrete or Metal, Post Top, direct buried		6.67	6.41
Underground Wiring (per run)			
All sizes and types of fixtures		$15.28	$15.28

Newfoundland Power Inc.

Conservation and Demand Management ("CDM") Cost Deferral Account

Proposed Definition

CDM Cost Deferral Account 188xx

This account shall be charged with the costs incurred in implementing the CDM Program Portfolio.

These costs include the CDM Program Portfolio costs incurred by Newfoundland Power for: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, and program evaluation costs.

This account shall also be charged the costs of major CDM studies such as comprehensive customer end use surveys and CDM potential studies that cost greater than $100,000.

Transfers to, and from, the proposed account will be tax-effected.

This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred.

Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Clause or as otherwise ordered by the Board.

Newfoundland Power Inc.

Electrification Cost Deferral Account

Proposed Definition

Electrification Cost Deferral Account 189xx

This account shall be charged with the costs incurred in implementing the Customer Electrification Program Portfolio.

These costs include: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, program evaluation costs and the costs to operate Company-owned charging stations.

This account shall also be charged the costs of major studies such as pilot programs, comprehensive customer surveys and potential studies that cost greater than $100,000.

This account shall be credited with the receipt of government funding related to electrification programs and any revenues associated with the operation of Company-owned charging stations.

The account will exclude any expenditure properly chargeable to plant accounts. The account shall also exclude electrification expenditures that are general in nature and not associated with a specific electrification program, such as costs associated with providing electrification awareness, and general planning, research and supervision costs.

Transfers to, and from, the proposed account will be tax-effected.

This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred.

Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Clause or as otherwise ordered by the Board.

Newfoundland Power Inc.

Proposed Changes to the Rate Stabilization Clause

It is proposed that Clause II.7 of the Rate Stabilization Clause be replaced with the following:

7. On March 31st of each year, the Rate Stabilization Account shall be increased on a before tax basis, by the CDM Cost Recovery Transfer.

   The CDM Cost Recovery Transfer, expressed in dollars, will be calculated to provide for the recovery of costs charged annually to the Conservation and Demand Management Cost Deferral Account (the "CDM Cost Deferral"), commencing in the year following the year in which the CDM Cost Deferral is charged to the CDM Cost Deferral Account. Beginning January 1, 2021, annual charges to the CDM Cost Deferral will be recovered over 10 years. Annual charges to the CDM Cost Deferral up to December 31, 2020, will continue to be recovered over 7 years in accordance with Order. No. P.U. 13 (2013).

   The CDM Cost Deferral Account will identify the year in which each CDM Cost Deferral was incurred.

   The CDM Cost Recovery Transfer for each year will be determined as follows:

   A + B

   Where:

   A = the sum of individual amounts representing 1/7th of each CDM Cost Deferral up to December 31, 2020, which individual amounts shall be included in the CDM Cost Recovery Transfer for 7 years in which the CDM Cost Deferral was recorded.

   B = the sum of individual amounts representing 1/10th of each CDM Cost Deferral, beginning January 1, 2021, which individual amounts shall be included in the CDM Cost Recovery Transfer for 10 years following the year in which the CDM Cost Deferral was recorded.

It is proposed that Clause II.9 of the Rate Stabilization Clause be replaced with the following:

9. On March 31st of each year, beginning in 2022, the Rate Stabilization Account shall be increased on a before tax basis, by the Electrification Cost Recovery Transfer.

   The Electrification Cost Recovery Transfer, expressed in dollars, will be calculated to provide for the recovery of costs charged annually to the Electrification Cost Deferral Account over a 10-year period, commencing in the year following the year in which the Electrification Cost Deferral is charged to the Electrification Cost Deferral Account.

   The Electrification Cost Deferral Account will identify the year in which each Electrification Cost Deferral was incurred.

   The Electrification Cost Recovery Transfer for each year will be the sum of individual amounts representing 1/10th of each Electrification Cost Deferral, which individual amounts shall be included in the Electrification Cost Recovery Transfer for 10 years following the year in which the Electrification Cost Deferral was recorded.