DELIVERED BY HAND

December 12, 2023

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

Attention: Jo Galarneau
Executive Director and Board Secretary

Dear Ms. Galarneau:

Re: 2025/2026 General Rate Application

1. Background

In Order No. P.U. 3 (2022), the Board ordered Newfoundland Power Inc. ("Newfoundland Power" or the "Company") to file its next general rate application no later than June 1, 2024.

On November 9, 2023, the Company filed a *2025/2026 General Rate Application* which sought the approval of Newfoundland Power's 2024 forecast average rate base and rate of return on rate base, as well as approval of the Company's 2025 and 2026 test year revenue requirements.

By way of a letter dated November 17, 2023, the Board directed that the Company file a separate application relating to approval of its 2024 forecast average rate base and rate of return on rate base. On November 23, 2023, the Company filed its stand-alone *2024 Rate of Return on Rate Base Application*. By way of a letter dated November 27, 2023, the Board directed further information to be filed with respect to the Company's *2025/2026 General Rate Application*.

To reduce the potential for confusion, the Company is withdrawing its November 9, 2023 *2025/2026 General Rate Application* filing. The Company asks that the Board remove the outdated filing from its website. Parties that were provided paper copies are asked to follow the replacement instructions outlined below.

The enclosed *2025/2026 General Rate Application* (the "Application") has been revised to remove proposals relating to its 2024 forecast average rate base and rate of return on rate base, now contained in the *2024 Rate of Return on Rate Base Application*. Other Application proposals remain unchanged.

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

Additional information requested in the Board's letter of November 27, 2023 will be provided under separate cover on or before December 13, 2023.

2. The Filing

Enclosed with this letter are the original and 11 copies of the Application. In efforts to reduce waste, the Company has not provided new binders. The Company asks that the parties remove the contents of the binders provided on November 9, 2023 and replace with the paper copies of this Application.

3. Application Proposals

The Company's proposals are contained in paragraphs 9 to 16 of the Application. A summary of the proposals follows.

<u>Customer Rates</u>

The Application proposes that the Board approve an overall average increase in Newfoundland Power's customer rates of 5.5%, with effect from July 1, 2025. The proposed rate change is necessary for Newfoundland Power to have a reasonable opportunity to earn a just and reasonable return in each of 2025 and 2026 in accordance with section 80 of the *Public Utilities Act*.

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

Rate Class	Average Increase
Domestic	5.5%
General Service 0-100 kW (110 kVA)	5.5%
General Service 110-1000 kVA	5.4%
General Service 1000 kVA and Over	5.3%
Street and Area Lighting	5.9%

<u>Cost of Capital</u>

The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2025 and 2026 is 9.85% 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.

Regulatory Accounting

The Application proposes that:

1. The Board approve amendments to Clause II.9 of the Rate Stabilization Clause for the reasons set out in the evidence filed in support of this Application;

2. The Board approve amendments to the definition of the Demand Management Incentive Account for the reasons set out in the evidence filed in support of this Application, effective January 1, 2025;

3. The Board approve amendments to the definition of the Pension Capitalization Cost Deferral Account for the reasons set out in the evidence filed in support of this Application, effective January 1, 2025;

4. The Board approve the amortization over the 2025 to 2027 period of:

   a) an estimated $1,000,000 in Consumer Advocate and Board hearing costs associated with the Application; and
   b) a forecast 2024 revenue shortfall of approximately $6,722,000 and a forecast 2025 revenue shortfall of approximately $16,761,000.

4. Process and 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.

A copy of the Application has been posted to the Company's website at www.newfoundlandpower.com. The Application has also been forwarded directly to Newfoundland and Labrador Hydro, and Mr. Dennis Browne, K.C., the Consumer Advocate.

We trust you will find the enclosed Application to be in order. Please contact the undersigned with any questions.

Yours truly,

Lindsay Hollett
Senior Legal Counsel &
Assistant Corporate Secretary

Enclosures

c. Shirley Walsh
Newfoundland and Labrador Hydro

Dennis Browne, K.C.
Browne Fitzgerald Morgan & Avis

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1. Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc.

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

IN THE MATTER OF an application by Newfoundland Power Inc. ("Newfoundland Power"): to establish customer electricity rates for 2025 and 2026 (the "Application").

TO: The Board of Commissioners of Public Utilities of Newfoundland and Labrador (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. 3 (2022), the Board ordered Newfoundland Power to file its next general rate application no later than June 1, 2024.

4. In Order No. P.U. 3 (2022), 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. 3 (2022), the Board approved Newfoundland Power's use of the depreciation rates and methodology as recommended in the *2019 Depreciation Study* for the calculation of its depreciation expense with effect from January 1, 2022.

6. In Order No. P.U. 3 (2022), the Board approved the establishment of an Electrification Cost Deferral Account. Proposed amendments to Clause II.9 of the Rate Stabilization Clause to allow for recovery of costs charged annually to the Electrification Cost Deferral Account have not yet been approved.

7. In Order No. P.U. 32 (2007), the Board approved the Demand Management Incentive Account (the "DMI Account") and the definition of the DMI Account to be included in

Newfoundland Power's System of Accounts. In Order No. P.U. 43 (2009), the Board approved continued use of the DMI account.

8. In Order No. P.U. 3 (2022), the Board approved the creation of the Pension Capitalization Cost Deferral Account.

B. Newfoundland Power Proposals:

General

9. 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 2026, for the reasons set out in the evidence filed in support of the Application.

10. Newfoundland Power proposes that the Board approve, for costs incurred commencing January 1, 2021, amendments to Clause II.9 of the Rate Stabilization Clause, as set out in Schedule A, for the reasons set out in the evidence filed in support of this Application.

11. Newfoundland Power proposes that the Board approve amendments to the definition of the DMI Account for the reasons set out in the evidence filed in support of this Application, effective January 1, 2025.

12. Newfoundland Power proposes that the Board approve amendments to the definition of the Pension Capitalization Cost Deferral Account for the reasons set out in the evidence filed in support of this Application, effective January 1, 2025.

13. 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 30-month period commencing July 1, 2025 and ending December 31, 2027, 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.

14. Newfoundland Power proposes that the Board approve the amortization of a forecast 2024 revenue shortfall of approximately $6,722,000 and a forecast 2025 revenue shortfall of approximately $16,761,000, for the reasons set out in the evidence filed in support of this Application, over a 30-month period, commencing July 1, 2025 and ending December 31, 2027.

<u>2025/2026 Customer Rates</u>

15. Newfoundland Power proposes that the Board approve an overall average increase in customer rates of 5.5%, with effect from July 1, 2025, based upon:

    (a) a forecast average rate base for 2025 of $1,406,816,000 and for 2026 of $1,451,200,000;

    (b) a rate of return on average rate base for 2025 of 7.40% in a range of 7.22% to 7.58% and for 2026 of 7.21% in a range of 7.03% to 7.39%; and

    (c) forecast revenue requirements from customer rates for 2025 of $768,770,000 and for 2026 of $789,602,000.

16. Newfoundland Power proposes that the Board approve rates, tolls and charges, 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	5.5%
General Service 0-100 kW (110 kVA)	5.5%
General Service 110-1000 kVA	5.4%
General Service 1000 kVA and Over	5.3%
Street and Area Lighting	5.9%

all to be effective for service provided on and after July 1, 2025, as more fully described in the evidence filed in support of the Application.

C. Order Requested:

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

    (a) pursuant to section 80 of the Act, the continued suspension of an automatic adjustment formula as set out in paragraph 9 of the Application;

    (b) pursuant to sections 70 and 80 of the Act, amendments to Clause II.9 of the Rate Stabilization Clause as set out in paragraph 10 of the Application;

    (c) pursuant to sections 70 and 80 of the Act, amendments to the definition of the DMI Account as set out in paragraph 11 of the Application;

(d) pursuant to sections 70 and 80 of the Act, amendments to the definition of the Pension Capitalization Cost Deferral Account as set out in paragraph 12 of the Application;

(e) pursuant to sections 58 and 80 of the Act, the amortizations set out in paragraphs 13 and 14 of the Application;

(f) pursuant to sections 70 and 80 of the Act, rates, tolls and charges, to be effective for service provided on and after July 1, 2025, as set out in Schedule B to the Application and reflected in paragraphs 15 and 16; and

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

D. Communications:

18. Communication with respect to this Application should be forwarded to the attention of Lindsay Hollett and Liam O'Brien, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador, this 12th day of December, 2023.

NEWFOUNDLAND POWER INC.

Lindsay Hollett

Lindsay Hollett and Liam O'Brien
Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5364
Telecopier: (709) 737-2974
Email: lhollett@newfoundlandpower.com
lobrien@curtisdawe.com

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

IN THE MATTER OF an application by Newfoundland Power Inc. ("Newfoundland Power"): to establish customer electricity rates for 2025 and 2026 (the "Application").

AFFIDAVIT

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

1. THAT I am President and Chief Executive Officer of Newfoundland Power Inc.;

2. THAT I have read and understand the foregoing Application; and

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

SWORN TO before me at the City of St. John's in the Province of Newfoundland and Labrador this 12th day of December, 2023:

Lindsay Hollett

Barrister, NL

Lindsay S. Hollett
Barrister, NL

Gary Murray

NEWFOUNDLAND POWER INC.

RULES AND REGULATIONS

1. INTERPRETATION:

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

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

(b) Unless the context requires otherwise these Rates, Rules and Regulations shall be interpreted such that words imparting the singular include the plural and vice versa.

2. CLASSES OF SERVICE:

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

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

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

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

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

NEWFOUNDLAND POWER INC.

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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 their 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.

RULES AND REGULATIONS

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 their 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 their 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 their 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, their 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.

NEWFOUNDLAND POWER INC.

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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 the Customer’s 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 their 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.

NEWFOUNDLAND POWER INC.

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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 Project Cost Recovery Rider (collectively, “Hydro’s Rate Adjustments”).

I. RATE STABILIZATION ADJUSTMENT ("A")

The Rate Stabilization Adjustment (“A”) 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 adjustment expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{\mathbf{B1 + B2 + B3 + C}}{\mathbf{D}}$$

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.

B3 = the Muskrat Falls Project Cost Recovery Rider.

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.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

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:

$$\mathbf{(G/H - P) \quad x \quad H}$$

Where:

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

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

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:

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

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.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

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

(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.

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

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

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

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 ("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, all historical balances and annual charges to the CDM Cost Deferral will be recovered over 10 years.

   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 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.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

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

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 2025, 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.

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 .... $17.02 per month
Exceeding 200 Amp Service .... $22.02 per month

Energy Charge:
All kilowatt-hours .... @ 14.178¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service .... $17.02 per month
Exceeding 200 Amp Service .... $22.02 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 ....$13.59 per month
Single Phase ....$21.59 per month
Three Phase...$33.59 per month

Demand Charge:
$10.33 per kW of billing demand in the months of December, January, February and March and $7.83 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 .... @ 14.030¢ per kWh
All excess kilowatt-hours .... @ 10.847¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 23.479 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 .... $13.59 per month
Single Phase .... $21.59 per month
Three Phase .... $33.59 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: .... $52.60 per month

Demand Charge:
$8.65 per kVA of billing demand in the months of December, January, February and March and $6.15 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 .... @ 12.121¢ per kWh
All excess kilowatt-hours .... @ 10.011¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 23.479 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: .... $91.66 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 75,000 kilowatt-hours .... @ 11.730¢ per kWh
All excess kilowatt-hours .... @ 9.925¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 23.479 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)	$19.79	$21.07
150W (14,400 lumens)	24.82	-
250W (23,200 lumens)	35.57	-
400W (45,000 lumens)	50.07	-
Light Emitting Diode		
LED 100	$17.11	-
LED 150	20.38	-
LED 250	25.05	-
LED 400	29.84	-

Special poles used exclusively for lighting service*	
Wood	$6.79
30' Concrete or Metal, direct buried	9.27
45' Concrete or Metal, direct buried	15.37
25' Concrete or Metal, Post Top, direct buried	6.47
Underground Wiring (per run)*	
All sizes and types of fixtures	$15.44

* 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)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{\text{(Maximum Demand during Peak Period x 1,573 hours)}}$$

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 unmetered 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 2^{nd} 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.

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. The Company is responsible for serving approximately 87% of all electricity customers in Newfoundland and Labrador.

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 2022 to 2026 forecast.

Table 1-1:
Customers and Sales
2022 to 2026F

	2022	**2023F**	**2024F**	**2025F**	**2026F**
Customers	273,764	275,281	276,444	277,467	278,359
Sales (GWh)	5,784.5	5,949.2	5,981.4	6,017.9	5,978.3

The number of customers served by Newfoundland Power is forecast to increase by approximately 4,600, or 1.7%, from 2022 to 2026. Annual weather-adjusted energy sales are forecast to increase by approximately 194 GWh, or 3.4%, over the same period. The increase in energy sales reflects planned government electrification initiatives along with modest customer growth forecasted over the period.

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, in an environmentally responsible manner, consistent with reliable service.[1]

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

1.1.2 Newfoundland Power's Performance

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

Customers' satisfaction with the Company's service delivery has averaged 86% over the last decade. The highest levels of customer satisfaction are reported among customers who have had a direct interaction with Newfoundland Power employees.

The Company's electrical system operates reliably.

The average frequency of customer outages has been consistent with the Canadian average over the last decade. The average duration of customer outages has been approximately 40% better than the Canadian average over the same period. The Company's operations are focused on maintaining overall levels of service reliability for customers. Maintaining the service reliability experienced by customers is expected to require a continued focus on the renewal of aging assets over the next decade.

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

Newfoundland Power operates in an environmentally responsible manner.

The Company manages its construction and maintenance activities to avoid harm to the province's environment and biodiversity. Compliance with regulatory requirements and industry standards ensure protection of the environment. More than 99% of the electricity generated by Newfoundland Power is hydroelectric. As a result, the Company's direct emissions are lower than utilities with larger thermal generating portfolios.

Newfoundland Power demonstrates sound cost management.

The Company reduced its gross operating cost per customer by approximately 9.5% 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, Newfoundland Power is in the third year of a six-year plan to provide its customers with light emitting diode ("LED") street and area lighting. LED street lights offer customers lower rates for a more reliable service. The Company is aiming to replace all street lights with LED fixtures by 2026. Execution of the plan is currently on track, with approximately 30,000 LED street lights in service at year end 2022.

The efficiency of Newfoundland Power's operations can also be observed in the Company's response to widespread customer outages, such as Hurricane Larry in September 2021. Approximately 50,000 customers experienced outages as a result of Hurricane Larry. During this event, the Company's Outage Management System automatically assessed approximately 4,000 customer outage reports, the High Volume Call Answering system automatically resolved approximately 17,000 customer enquiries, and electrical system automation avoided approximately 3.8 million customer outage minutes without the assistance of field crews.

Costs to customers are also managed through conservation and demand management ("CDM") programs. Newfoundland Power and Hydro have jointly delivered CDM programs to electricity customers since 2009. CDM programs have delivered approximately $180.3 million in bill savings and $180.0 million in reduced system costs for Newfoundland Power's customers from 2009 to 2022.

Newfoundland Power recognizes that customers' electrical system requirements are evolving, particularly as electric vehicle adoption increases. The Company has designed a pilot project to investigate measures for managing the load of electric vehicle charging. The results of the pilot project are expected to inform the customer CDM programs to be launched by the utilities in 2026.

Labour costs account for over half of the Company's annual operating costs. Operating labour costs are forecast to increase by approximately 3.1% annually from 2022 to 2026. This is approximately 1% less than the Company's annual labour inflation over the same period.

Newfoundland Power will continue to focus on the delivery of reliable and environmentally responsible service to customers at the lowest possible cost.

1.1.3 Provincial Electricity Sector

The outlook for the provincial electricity sector is characterized by uncertainty that presents a risk to the delivery of least-cost, reliable service to Newfoundland Power's customers. The Muskrat Falls Project was fully commissioned in April 2023. The final cost of the Muskrat Falls Project is approximately $13.5 billion. This is nearly four times the book value of the province's electrical system prior to the project's commissioning.

The recovery of Muskrat Falls Project costs from customers commenced in 2022 through Hydro's Project Cost Recovery Rider. This mechanism permits the recovery of a small portion of the project costs. The full impact of Muskrat Falls Project costs on rates paid by Newfoundland Power's customers will not be known until the Provincial Government's rate mitigation plan is finalized and Hydro files its next general rate application.

The reliability of supply on the Island Interconnected System also remains uncertain. Hydro's latest update to its *Reliability and Resource Adequacy Study* was filed in 2022. The 2022 update provided a materially different outlook for the province's electricity system in comparison to prior assessments. The update reflects lower reliability assumptions for the Labrador-Island Link ("LIL") and identifies the need for backup generation on the Island Interconnected System in the event of an outage to the LIL.

Based on this revised outlook, Hydro has recommended extending the operation of its Holyrood Thermal Generating Station ("Holyrood") until 2030, or until such a time that alternative generation is commissioned. The costs to continue Holyrood's operation are substantial, and its ability to serve as a reliable source of supply is not assured given its age and operating history.

The Government of Canada has stated that a clean electricity grid will be the backbone of a prosperous, low-carbon future. Federal regulations to achieve net-zero emissions from the electricity grid, while maintaining affordable and reliable supply for Canadians, are expected to be finalized in 2024. The full impact of these regulations on the near and longer-term outlooks for the provincial electricity sector and Newfoundland Power's customers is uncertain at this time.

1.1.4 Risk and Return

In this Application, Newfoundland Power is asking the Board to determine an appropriate capital structure for ratemaking purposes and an appropriate return on common equity invested in the Company.

Newfoundland Power's business risks in 2023 remain largely consistent with those described in the Company's *2022/2023 General Rate Application*. The Company's business risks continue to be defined by longstanding factors. These factors include weak service territory demographics in comparison to the rest of Canada, a harsh operating environment, the Company's small size and its limited cost flexibility. The provincial economic outlook remains weak with economic indicators that continue to lag behind the rest of Canada, including historically low housing starts. The Muskrat Falls Project continues to pose risks to the delivery of least-cost, reliable service to customers.

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

1.2 APPLICATION PROPOSALS

1.2.1 2025 and 2026 Revenue Requirements

In this Application, Newfoundland Power is proposing an average increase in customer rates of approximately 5.5% effective July 1, 2025 to recover its 2025 and 2026 revenue requirements. This rate increase is primarily the result of increases in the Company's costs since its last general rate application and a proposed increase in its return on equity.

Increases in the Newfoundland Power's costs since its last general rate application, revised for the increase in 2024 return on rate base proposed in the Company's *2024 Rate of Return on Rate Base Application*, results in a 3.9% increase in the revenue required from customer rates. This includes the cost of continued investment in the electrical system, increased operating costs and the effects of amortizations proposed in this Application.

Expert evidence filed with this Application recommends a fair return on equity for Newfoundland Power in 2025 and 2026 of 9.85% on a common equity ratio of 45%. This return on equity represents a 1.6% increase in the revenue required from customer rates.

The Company proposes to apply the average rate increases outlined in this Application equally to all customer classes to the extent possible. Uniform increases in customer rates will continue to maintain class revenue-to-cost ratios within a range of 90% to 110%.

1.2.2 Wholesale Power Supply Costs

Newfoundland Power is dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers. Purchased power expense is Newfoundland Power's largest cost, accounting for approximately two-thirds of its revenue from rates. The Company has effectively no control over its power supply costs, including the wholesale rate charged by Hydro to Newfoundland Power. Currently, the Company recovers its power supply costs through a combination of base rate test year revenue requirements and regulatory mechanisms which are incorporated into the annual July 1st rate adjustment.

Under existing customer rates, variances in wholesale power supply costs from those included in the base rate test year revenue requirements approved by the Board are charged or credited to customers as part of the annual July 1st rate adjustment.

Typically, as part of general rate applications, wholesale power supply costs are "rebased" from flowing through the annual July 1st rate adjustment into base rate test year revenue requirements. Test year power supply costs are determined by applying the current wholesale rate charged by Hydro to Newfoundland Power to the energy purchases forecasted in those years.

The current wholesale rate was approved by the Board in Order No. P.U. 30 (2019) as part of Hydro's *2017 General Rate Application*. The wholesale rate was designed so that any change in energy purchases from the level set at that time are costed at the second block energy rate of 18.165¢ per kWh. The second block energy rate was based on the cost of fuel burned at Holyrood, which was the marginal cost of energy when the wholesale rate was determined.

The wholesale rate will be re-designed as part of Hydro's next general rate application. This is expected to include a second block energy rate that will reflect the cost of energy exports, which is now considered the marginal cost of energy. The marginal cost of energy exports is forecast to be in the range of 3 to 5¢ per kWh on an annual basis in 2025 and 2026.

Hydro's next general rate application was ordered by the Board to be no later than September 30, 2020. With delays in LIL commissioning and rate mitigation being finalized, Hydro currently expects the earliest timeframe for filing its next general rate application to be in the latter half of 2024, contingent on Hydro having certainty related to the Provincial Government's rate mitigation plan.

Given the uncertainty in the implementation date of a new wholesale rate and the potential material change in marginal energy costs, Newfoundland Power has not rebased its forecast power supply energy costs into base rate 2025 and 2026 revenue requirements. Variances in power supply energy costs in those years from the level reflected in existing customer rates approved by the Board will continue to be charged or credited to customers as part of the annual July 1st rate adjustment.

This approach will result in power supply costs ultimately recovered from customers related to 2025 and 2026 being based on the wholesale rate actually in effect in those years.

1.2.3 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 2026 test year. Circumstances do not warrant reinstatement of a formula in this jurisdiction at this time. For example, long-term Canada bond yields form the basis of a formula's operation. While bond yields have increased, there has been continued volatility in financial markets in recent years.

The Application also proposes the following, all of which are more fully described in Newfoundland Power's evidence:

i. amendments to the Rate Stabilization Clause to recover costs associated with the Electrification Cost Deferral Account;
ii. amendments to the definition of the Demand Management Incentive Account and the Pension Capitalization Cost Deferral Account; and
iii. amortizations associated with hearing costs and forecast 2024 and 2025 revenue shortfalls.

SECTION 2: CUSTOMER OPERATIONS

2.1 OVERVIEW

Newfoundland Power provides reliable and environmentally responsible service to its customers at the lowest possible cost.

The Company's customer service delivery is efficient and responsive to customers' expectations. Customer service costs were reduced by approximately 15% from 2013 to 2022. This cost reduction was achieved while serving more customers and responding to more customer enquiries. While costs declined, customer satisfaction remained consistent.

A new Customer Information System was successfully implemented in 2023. The new system will provide continuity in the Company's customer service delivery over the longer term.

CDM programs have continued to yield cost savings for customers. CDM programs have delivered approximately $180.3 million in bill savings and approximately $180.0 million in reduced system costs for Newfoundland Power's customers since 2009.

Newfoundland Power's electrical system operates reliably. The frequency of customer outages has been consistent with the Canadian average over the last decade. The average duration of customer outages has been approximately 40% better than the Canadian average over the same period. The Company continues to invest in its electrical system to repair or replace deteriorated and defective equipment and maintain service reliability for customers.

Newfoundland Power operates in an environmentally responsible manner to serve its customers. The Company complies with all applicable environmental legislation and regulations and maintains its own policies and procedures to avoid harm to the environment and protect the province's biodiversity.

The Company aims to maintain efficiency in serving its customers. Operating costs per customer were reduced by approximately 9.5% on an inflation-adjusted basis over the last decade. Technology-driven initiatives continue to be integral to balancing the quality and cost of the service provided to customers.

Gross operating costs are forecast to increase by approximately 3.9% per year from 2022 to 2026. Operating labour costs are forecast to increase by 3.1% 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 and environmentally responsible service to its customers at the lowest possible cost.

2.2 CUSTOMER SERVICE

2.2.1 Customer Service Delivery

Newfoundland Power expects to serve approximately 278,000 customers by 2026.

The Company's customer service delivery is focused on providing an efficient and effective response to customers' service requests and enquiries. Customers are offered a variety of communication channels through which to receive service from Newfoundland Power, including telephone, email and a website with self-service tools and a web chat feature.

Table 2-1 provides the number of customer enquiries received annually from 2018 to 2022.

Table 2-1:
Customer Enquiries
2018 to 2022
(000s)

	2018	**2019**	**2020**	**2021**	**2022**
Telephone	470	458	433	391	394
Email	91	87	103	119	116
Website	1,823	1,771	2,193	2,006	2,123
Total	**2,384**	**2,316**	**2,729**	**2,516**	**2,633**

The number of enquiries received from customers exceeded 2.6 million in 2022. This was 10% higher than the number of customer enquiries received in 2018.[1] The increase in customer enquiries corresponds with customers' increased use of digital communication channels. This is consistent with Newfoundland Power's long-term experience and current industry trends.[2]

[1] (2,633,000 – 2,384,000) / 2,384,000 = 0.10, or 10%.
[2] A survey conducted by McKinsey & Company in April 2021 noted continued growth in "fully digital" users in recent years. See McKinsey & Company, "*What's next for digital consumers*," May 23, 2021.

The Company's website is the most used communication channel among customers. Visits to the website increased by 16% from 2018 to 2022.[3] In 2022, 80% of visits to the website were driven by customers accessing information on their accounts and outage information.[4]

The Company regularly enhances the features available on its website to keep pace with customers' preference for digital communication. The website was enhanced in 2021 with the implementation of an online chat feature, which was fully rolled out to all webpages in 2022.[5] The online chat feature allows customers to communicate directly with a Customer Service Representative on the website. There were approximately 7,400 customer interactions handled through the online chat in 2022. The number of customer interactions increased in 2023, with approximately 15,100 interactions by the end of the third quarter. The Company plans to expand the online chat feature with the addition of an automated option that will provide after-hours service for customers.[6]

Digital services available to customers have also been enhanced through the introduction of electronic identity verification. An online tool now provides near-instant identification verification for customers requesting electrical service at rental properties.[7] As a result,

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[3] (2,123,000 - 1,823,000) / 1,823,000 = 0.16, or 16%.

[4] Newfoundland Power's website generated approximately 5.5 million page views in 2022. Approximately 3.1 million views were on account-related pages and 1.3 million views were on outage-related pages ((3.1 million + 1.3 million) / 5.5 million = 0.80, or 80%).

[5] 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).

[6] Automated webchat services use artificial intelligence to respond to customers' enquiries in a secure and timely manner. Enhancement of webchat to include automated options was outlined in Newfoundland Power's *2024 Capital Budget Application.*

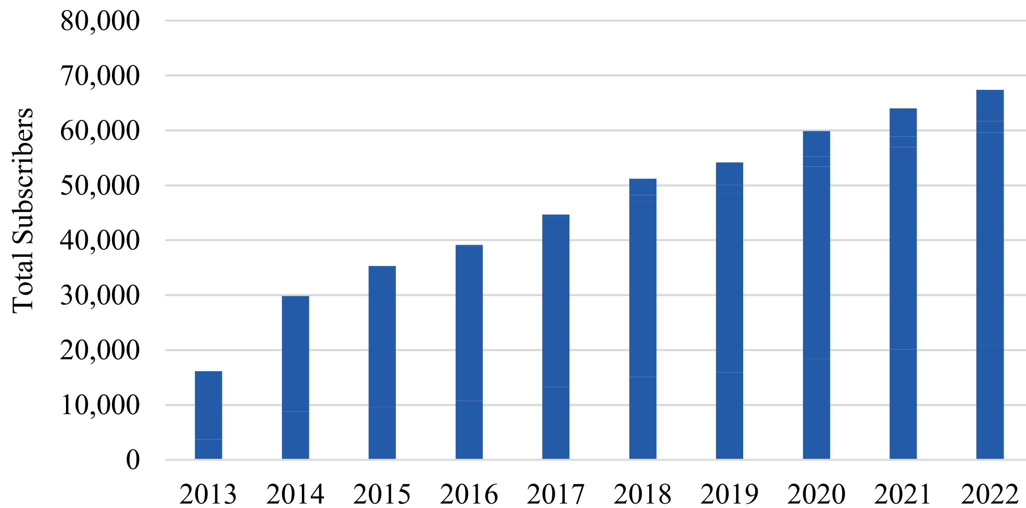
[7] Electronic identity verification uses a range of data sources to generate questions and answers that only the customer would know, providing secure and accurate verification of an individual's identity.

customers no longer need to visit a Company office to present identification. Over 3,000 customers availed of this service in 2022.

Newfoundland Power continues to enhance its use of social media to share information with 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 from 2013 to 2022.

Figure 2-1:
Social Media Subscribers
2013 to 2022



The number of subscribers to Newfoundland Power's social media channels has more than quadrupled since 2013.[8] The Company had over 67,000 subscribers across its social media accounts in 2022.[9]

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8 Newfoundland Power's social media channels had approximately 16,000 subscribers in 2013 and approximately 67,000 subscribers in 2022 (67,000 / 16,000 = 4.2).

9 The Company maintains social media accounts on Facebook, X (previously known as Twitter), Instagram and LinkedIn.

2.2.2 Customer Service Performance

Newfoundland Power measures its customer service performance through a combination of performance targets and customer surveys. These metrics are designed to ensure the Company provides service that is timely and responsive to customers' expectations.

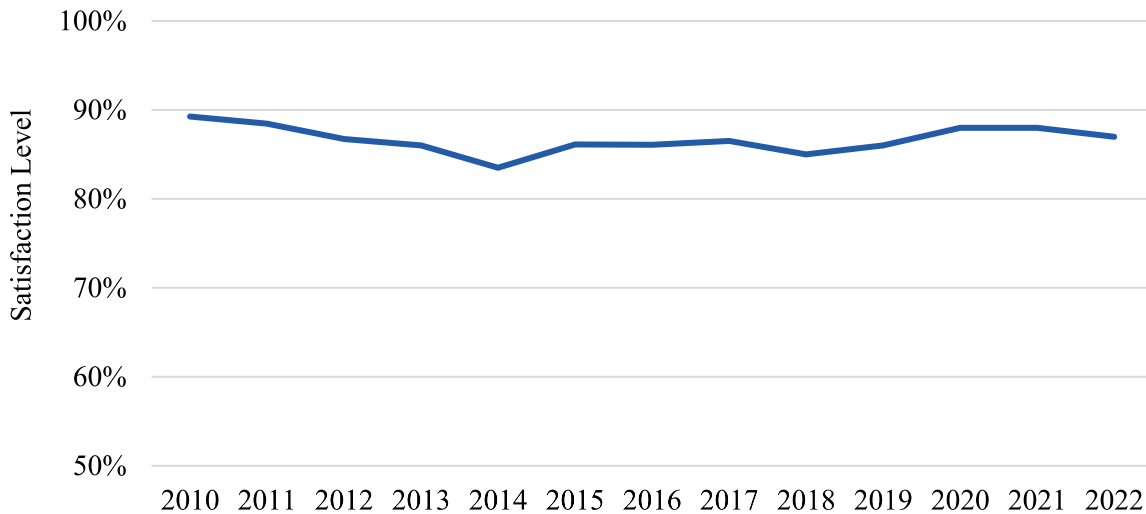
Over 2,000 new requests for electrical service are completed annually. Newfoundland Power aims to provide timely access to service by completing new service connections within five business days. This target was achieved in 2022 with an average response time of 4.8 days.

Over 11,000 trouble calls from customers experiencing issues with their electrical service are received annually. The Company targets a two-hour response to trouble calls to provide a timely resolution of customers' service issues. This target was achieved in 2022 with an average response time of 1.7 hours.

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

Figure 2-2 shows customers' overall satisfaction with Newfoundland Power's service delivery from 2013 to 2022.

Figure 2-2:
Customer Satisfaction
2013 to 2022



Customers' overall satisfaction with Newfoundland Power's service delivery was 87% in 2022. This is reasonably consistent with customers' average level of satisfaction over the last decade.[10]

Customers who have had a direct interaction with the Company report the highest levels of satisfaction. Customers who interacted with Newfoundland Power in the field reported an average satisfaction rate of 93% in 2022. Customers who interacted with the Company by telephone reported an average satisfaction rate of 94% in 2022.

[10] Customers' satisfaction with the Company's service delivery averaged approximately 86% from 2013 to 2022.

2.2.3 Customer Service Efficiency

Newfoundland Power aims to maintain efficient customer service delivery. The Company reduced its customer service costs by 15% from 2013 to 2022.[11] This cost reduction was achieved while serving 18,000 more customers and responding to over a million more customer enquiries annually.[12]

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

For example, Newfoundland Power received over two million calls from customers over the last five years. The efficiency of handling customer calls is enhanced through automation provided by an Interactive Voice Response ("IVR") system. The IVR system allows customers to access information by telephone without having to speak directly to a Customer Service Representative. The average cost of a customer call handled by the IVR system is approximately $0.31, compared to over $13 for a call handled by a Customer Service Representative. The IVR system handled nearly half of customer calls over the last five years.

Newfoundland Power also enhanced its efficiency in 2019 with the introduction of the LED Street and Area Lighting service option for customers.[13] LED street lights provide customers with lower rates for a more reliable service that requires less maintenance. The customer rates for

[11] Newfoundland Power's customer service costs were approximately $9.5 million in 2013 and $8.1 million in 2022 (($8.1 million - $9.5 million) / $9.5 million = -0.15, or -15%).

[12] The Company served approximately 256,000 customers in 2013 and 274,000 customers in 2022 (274,000 – 256,000 = 18,000). The Company received approximately 1.5 million customer enquiries in 2013, compared to approximately 2.6 million enquiries in 2022.

[13] LED Street and Area Lighting was approved in Order No. P.U. 2 (2019).

LED street lights are between 13% to 45% less than the rates for equivalent high-pressure sodium ("HPS") street lights.[14]

The Company commenced its six-year plan to replace all 60,000 HPS street lights in its service territory with LED fixtures in 2021. Execution of the plan is on track with approximately 30,000 LED street lights installed at the end of 2022. The remainder have HPS fixtures, which are expected to be replaced in accordance with the *LED Street Lighting Replacement Plan.*[15]

Newfoundland Power's Customer Service System was integral to the Company's customer service efficiency since 1993.[16] In 2023, the Company successfully executed its three-year project to replace this system, which had become obsolete.[17]

The new Customer Information System will ensure customers continue to be served in an efficient and responsive manner over the longer term.[18] The new system offers a 360-degree view of the customer through a single interface that provides all the necessary information to respond to customers' enquiries.[19] The new system also provides greater automation, including the ability to automatically transfer services when a customer moves to a new address.[20] These features, among others, support a timely and effective response to customers.

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14 The customer rates for Street and Area Lighting service and associated savings vary based on lighting output.

15 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan.*

16 The Customer Service System supported all essential customer service functions, including program and service delivery, account management and billing, and the management of customer communications.

17 The Board approved the *Customer Service System Replacement* project in Order No. P.U. 12 (2021).

18 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, Customer Service Continuity Plan.*

19 This differs from the previous premise-based model of the Customer Service System where relevant customer information was spread across multiple accounts.

20 Previously, when a customer transferred their electric service, many programs and services (e.g. Automatic Payment Plan, Customer Outage Notifications) were transferred manually.

2.2.4 Conservation and Demand Management

Newfoundland Power and Hydro have jointly delivered CDM programs for customers since 2009. CDM programs are delivered in accordance with multi-year plans that align with industry best practices and comply with all applicable orders of the Board. The current plan for customer programs commenced in 2021 and is scheduled to continue through 2025.[21]

Customer CDM programs have evolved in recent years in accordance with the utilities' current multi-year plan. The Business Efficiency Program was adjusted in 2021 to support demand management opportunities for commercial customers converting their facilities to electric space and water heating. The Energy Savers Kit Program was newly introduced in 2022 and provided over 2,000 income-qualified customers with an energy efficiency kit at no cost to the participant. The Insulation Rebate Program was expanded in 2022 to include rebates for duct insulation and air sealing to help customers manage space heating costs.

These modifications respond to customers' continued interest in CDM programs and help ensure programs continue to deliver energy savings for customers.

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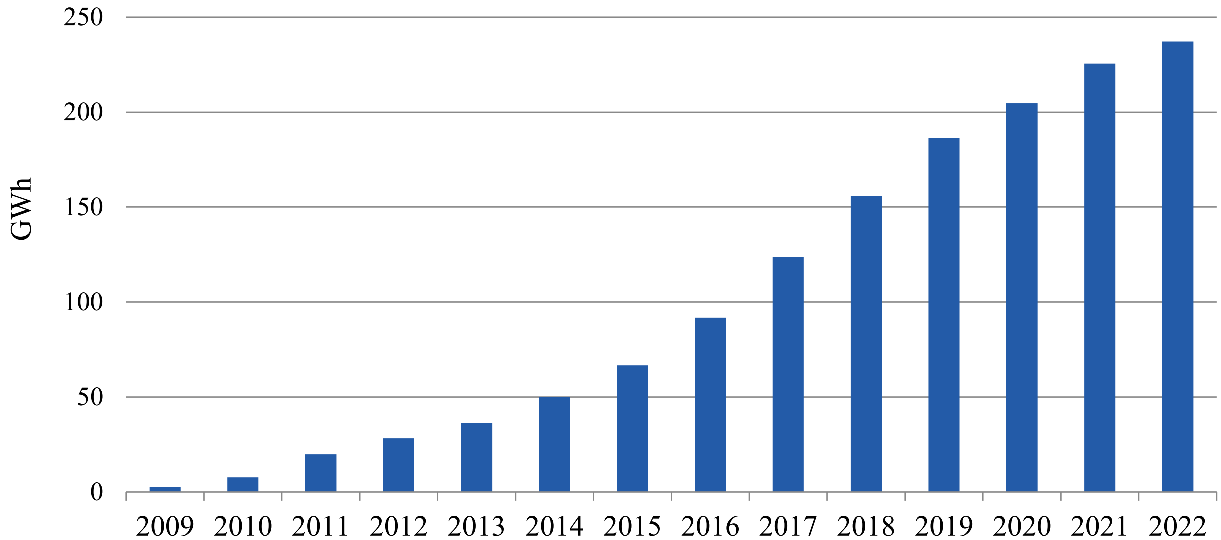
21 See Newfoundland Power's *2022/2023 General Rate Application, Volume 2, Electrification, Conservation and Demand Management Plan: 2021-2025*.

Figure 2-3 shows the annualized energy savings achieved by Newfoundland Power's customers through CDM programs from 2009 to 2022.[22]

Figure 2-3:
Customer Conservation Programs
Annualized Energy Savings
2009 to 2022



Customer participation in CDM programs yielded cumulative energy savings of 1,434 GWh from 2009 to 2022. Customers also achieved cumulative peak demand savings of 62 MW by 2022.

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

[22] 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 2022 will continue to provide energy savings each year until 2047.

totaling approximately $180.3 million at year end 2022. Second, all Newfoundland Power customers benefited from reduced system costs of approximately $180.0 million over this period.[23]

Newfoundland Power continues to evaluate its CDM programs annually and modify programs as necessary to ensure they remain cost-effective and beneficial for customers.[24] The Benchmarking Program that provides customers with home energy reports to reduce their energy usage was expanded in 2023 to include a fully digital option. The number of customers participating in the program is forecast to increase from approximately 70,000 in 2022 to 83,000 in 2023 as a result.[25] The Instant Rebates Program, which provides at-the-cash rebates for small energy-efficient products, and the Thermostat Rebate Program are both expected to conclude in 2023 due to changing market conditions.[26]

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23 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 $180 million system cost savings, approximately 72%, or $130 million, resulted from avoided energy costs and approximately 28%, or $50 million, resulted from avoided capacity costs.

24 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).

25 The Benchmarking Program resulted in the highest contribution to incremental energy and peak demand savings in 2022, accounting for approximately 52% of total energy savings and 63% of total peak demand savings.

26 The Instant Rebates Program is scheduled to conclude in 2023 due to the high saturation of LED bulbs in the province and changing ENERGY STAR standards leading to LED bulbs no longer being included in the program. The Thermostat Program provides on-bill rebates for digital and programmable thermostats. This program will conclude in 2023 due to the high saturation of these devices within the local market and decreasing energy savings per device.

Table 2-2 provides the estimated cost of delivering customer CDM programs under the current multi-year plan from 2022 to 2026F.[27]

Table 2-2:
Customer CDM Costs
2022 to 2026F
($000s)

	2022	**2023F**	**2024F**	**2025F**	**2026F**
General[28]	426	724	712	714	731
Program[29]	5,227	6,701	6,007	5,774	5,895
Total	**5,653**	**7,425**	**6,719**	**6,488**	**6,626**

Costs related to customer CDM initiatives are forecast to average approximately $6.6 million annually from 2022 to 2026.

With the continued implementation of CDM programs, customers are forecast to achieve cumulative energy savings of approximately 2,208 GWh by 2025 and peak demand savings of 68 MW.

2.3 OPERATIONS AND RELIABILITY MANAGEMENT

2.3.1 Operations Overview

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

[27] Excludes costs related to the delivery of electrification initiatives.
[28] General expenses include costs for customer education and support (e.g. responding to customer enquiries).
[29] Program delivery costs include costs directly associated with customer programs and related research.

Newfoundland Power owns and operates approximately 9,500 kilometers of distribution line, 2,100 kilometers of transmission line and 131 substations to serve customers throughout its service territory. The Company also operates 23 hydroelectric plants that generate approximately 438 GWh of low-cost electricity for customers annually.[30] Generation assets also include four combustion turbines and two diesel units which serve customers experiencing localized outages and provide system support when requested by Hydro.[31]

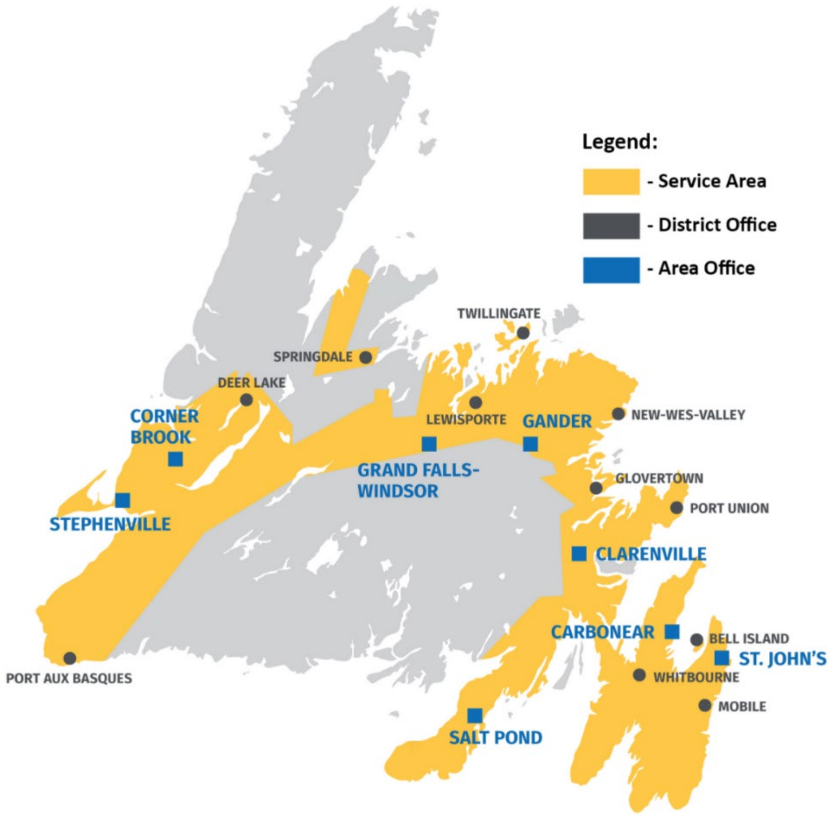
Newfoundland Power's service territory covers approximately 70,000 square kilometres. It spans almost 1,000 kilometres from Trepassey, on the Avalon Peninsula, to Port aux Basques, on the southwest coast, and over 300 kilometers from Fortune, on the Burin Peninsula, to Bonavista.

[30] 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.

[31] 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.

Figure 2-4 shows the Company's service territory, including the location of Company offices.

Figure 2-4:
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. In 2022, the Company employed 136 powerline technicians, 98 engineers and engineering technologists, and 100 employees with skilled trades.

2.3.2 Electrical System Reliability

Newfoundland Power's electrical system is constructed to meet national standards.[32] These standards ensure the electrical system operates reliably under conditions the Company could reasonably expect to occur throughout its service territory.

The reliability of Newfoundland Power's electrical system can be measured in both the frequency and duration of customer outages. Outage frequency is measured using the System Average Interruption Frequency Index ("SAIFI"). Outage duration is measured using the System Average Interruption Duration Index ("SAIDI").[33]

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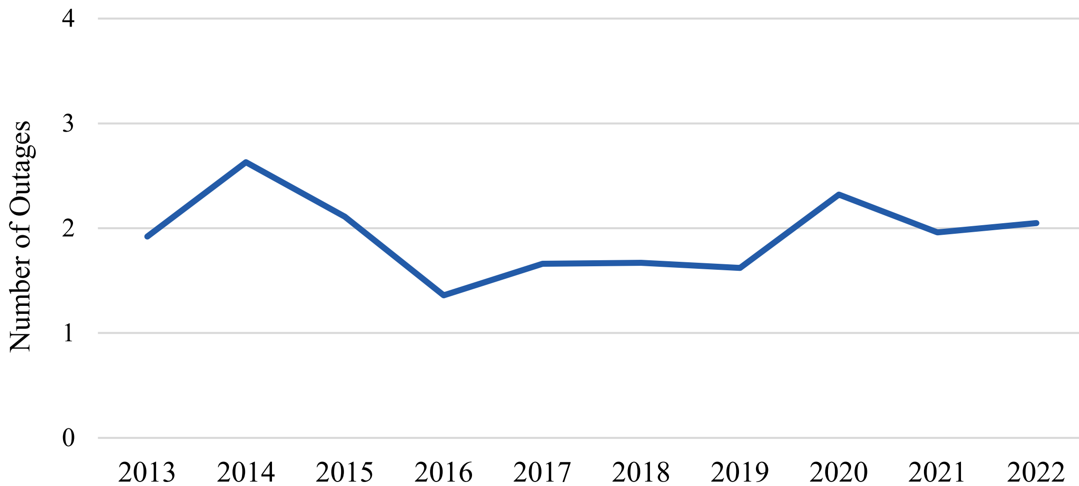
[32] The primary engineering standard for distribution and transmission systems is Canadian Standards Association ("CSA") standard *C22.3 No.1-15 Overhead Systems*.

[33] Newfoundland Power calculates its SAIFI and SAIDI in accordance with industry guidelines. SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers served. SAIDI is calculated by dividing the total number of customer outage minutes by the total number of customers served.

Figure 2-5 shows the average number of outages experienced by the Company's customers from 2013 to 2022 under normal operating conditions.[34]

Figure 2-5:
SAIFI Under Normal Operating Conditions
2013 to 2022

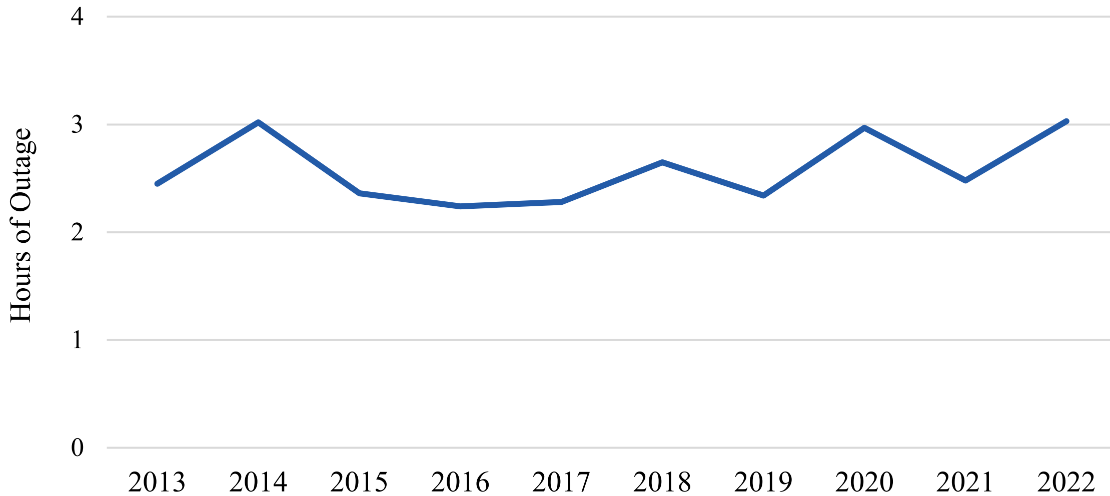


The frequency of customer outages has been reasonably consistent under normal operating conditions since 2013. Customers have experienced an average of one to three outages per year since 2013.

[34] Normal operating conditions exclude customer outages due to major events or loss of supply from Hydro. Electricity Canada defines major events as outages *"outside the control of the utility and are not caused from a general malaise of the system or equipment."* Major events are determined by applying an accepted Institute of Electrical and Electronic Engineers ("IEEE") methodology to the utility's daily performance measures.

Figure 2-6 shows the average duration of outages experienced by Newfoundland Power's customers from 2013 to 2022 under normal operating conditions.

Figure 2-6:
SAIDI Under Normal Operating Conditions
2013 to 2022

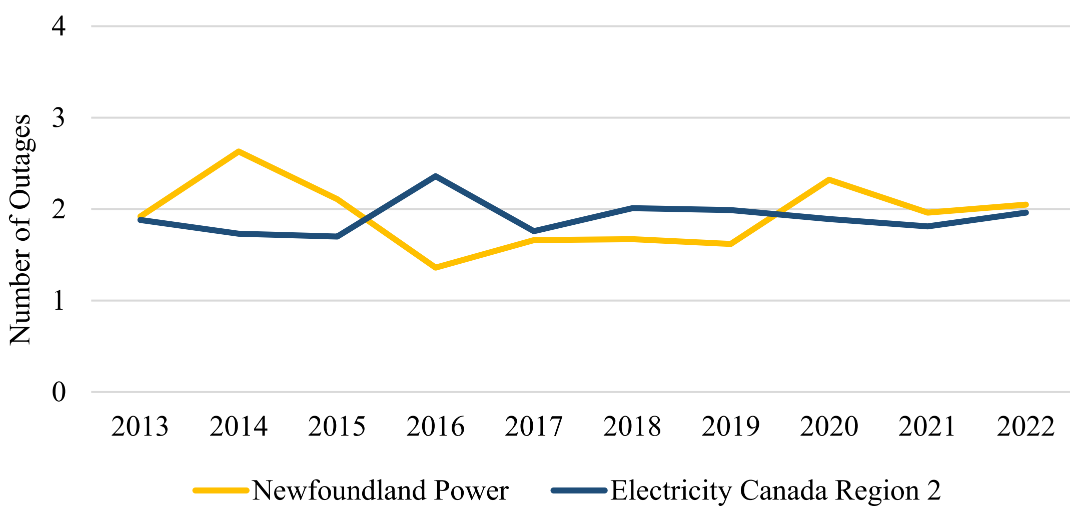


The duration of customer outages has also been reasonably consistent under normal operating conditions since 2013. On average, customers have experienced between two and three hours of outage per year over this period.

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 frequency of outages experienced by Newfoundland Power's customers in comparison to the Canadian average from 2013 to 2022.[35]

Figure 2-7:
Newfoundland Power vs. Canadian Average
SAIFI Under Normal Operating Conditions
2013 to 2022

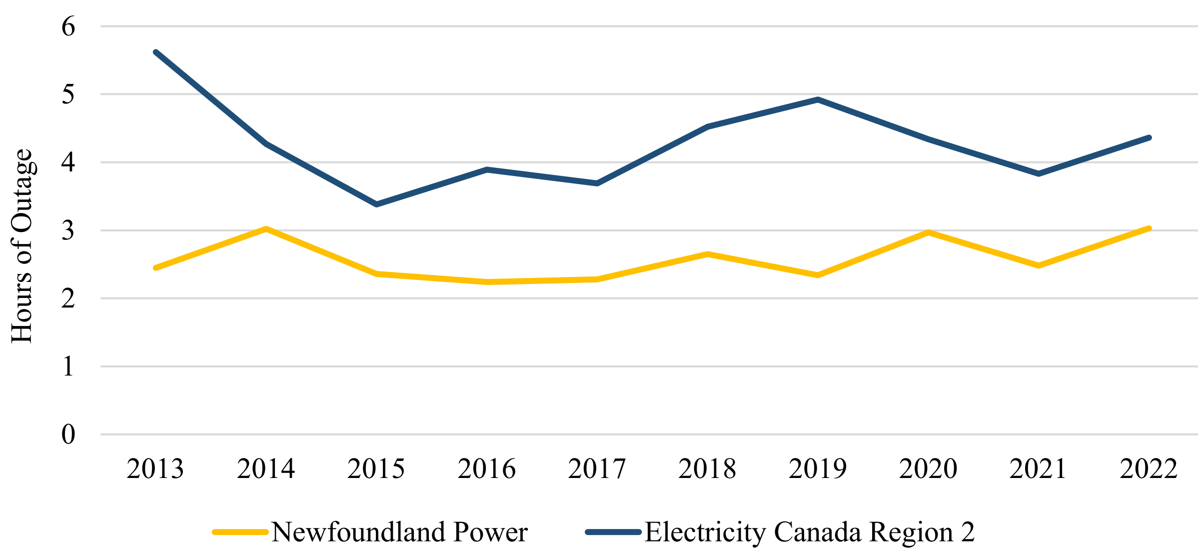


Since 2013, the average number of outages experienced by Newfoundland Power's customers has been broadly consistent with the Canadian average under normal operating conditions.

[35] References to the Canadian average in *Section 2: Customer Operations* refer to Region 2 utilities that are members of Electricity Canada. Region 2 utilities are those serving a mix of urban and rural markets. These include 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, Sask Power, Elexicon Energy and Blue Mountain Power Corp.

Figure 2-8 shows the average duration of outages experienced by Newfoundland Power's customers in comparison to the Canadian average from 2013 to 2022.

Figure 2-8:
Newfoundland Power vs. Canadian Average
SAIDI Under Normal Operating Conditions
2013 to 2022



Since 2013, the average duration of outages experienced by Newfoundland Power's customers has been approximately 40% better than the Canadian average under normal operating conditions.[36]

[36] Newfoundland Power's SAIDI averaged approximately 2.6 hours under normal operating conditions from 2013 to 2022, compared to an Electricity Canada Region 2 average of 4.3 hours ((4.3 – 2.6) / 4.3 = 0.40, or 40%).

Newfoundland Power's operations are focused on maintaining current levels of service reliability for customers under normal operating conditions.[37]

Maintaining service reliability for customers requires maintaining the general condition of the electrical system. The Company completes routine inspections of its electrical system to proactively identify deteriorated equipment and necessary repairs or replacements. Substations are inspected eight times annually, transmission lines are inspected annually, and distribution lines are inspected on a seven-year cycle. Equipment repairs or replacements are prioritized in accordance with the Company's long-term asset management strategies based on risk of failure, identified safety and environmental issues, and the likelihood of customer outages.[38] Over half of Newfoundland Power's annual capital investments are focused on the renewal of deteriorated assets to maintain reliable service for customers.

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 that can result in longer outage durations. For example, a hurricane may result in a single outage that lasts several days. These types of outages are generally categorized as "major events" by utility reporting standards.[39]

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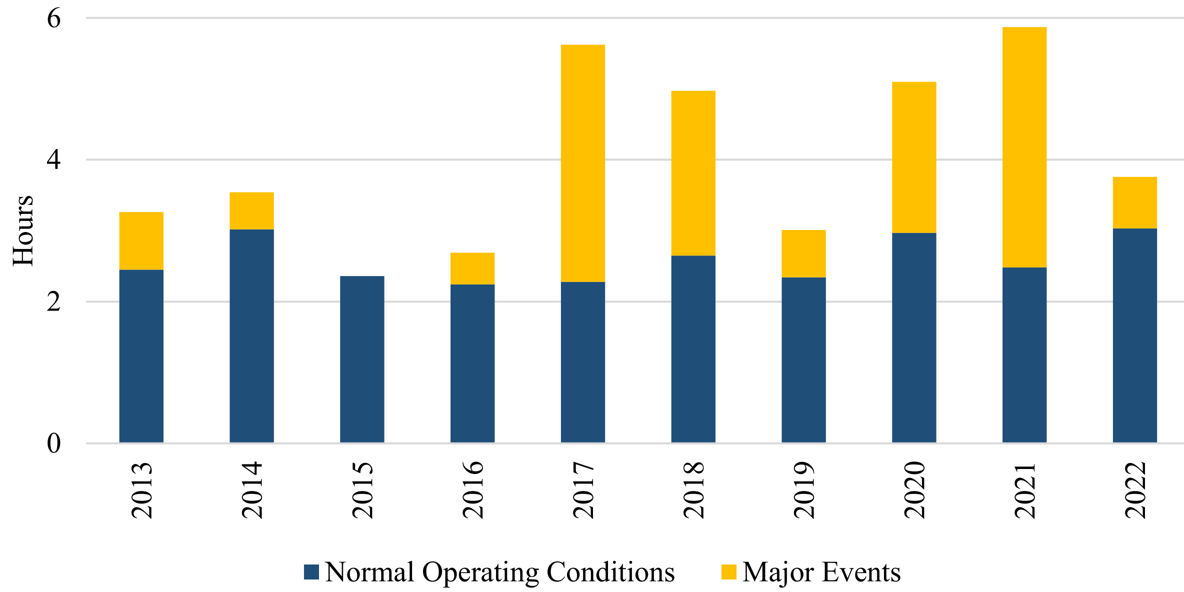
[37] Maintaining current levels of service reliability has been a focus for the Company for more than a decade. For example, in Newfoundland Power's *2010 General Rate Application*, the Company stated it considered then current levels of service reliability to be satisfactory (see *Volume 1 (1st Revision), Section 2: Customer Operations, Page 2-8,* Line 6).

[38] Newfoundland Power's asset management strategies include its *Transmission Line Rebuild Strategy, Substation Strategic Plan* and *Distribution Reliability Initiative*, among others. For more information, see the Company's *2024 Capital Budget Application.*

[39] See footnote 34 for a definition of major events.

Figure 2-9 shows the average duration of outages experienced by Newfoundland Power's customers including major events from 2013 to 2022.[40]

Figure 2-9:
Newfoundland Power
SAIDI Including Major Events
2013 to 2022



Major events have become more frequent in Newfoundland Power's service territory. Over the last decade, major events caused outages to Newfoundland Power's customers in nine years. This compares to four years with major events over the prior decade.[41]

Major events can have a material impact on the service reliability experienced by customers. For example, during Hurricane Larry in September 2021, the east coast of Newfoundland experienced wind gusts between 150 and 175 kilometers per hour. Approximately 50,000

[40] Figure 2-9 does not include outages caused by a loss of supply from Hydro.
[41] From 2003 to 2012, major events resulted in customer outages in 2007, 2010, 2011 and 2012.

Newfoundland Power customers experienced outages during this event, which increased the average duration of customer outages in 2021 from 2.5 hours under normal operating conditions, to 5.9 hours.[42]

Newfoundland Power aims to ensure an efficient restoration of service to customers following major events. The Company's operations technologies and electrical system automation are integral to this objective. During Hurricane Larry, 12 downline reclosers installed on the distribution system operated automatically to avoid 3.8 million customer outage minutes.[43] Newfoundland Power's Outage Management System automatically assessed and grouped over 4,000 outage reports into approximately 550 individual outages to facilitate a timely restoration of service to the remaining customers experiencing outages.[44] Using these technologies, service was restored to 80% of customers within 24 hours.

2.3.3 Environmental Responsibility

Newfoundland Power provides service to its customers in an environmentally responsible manner.

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42 Hurricane Larry in September 2021 resulted in approximately 47 million customer minutes of outage. Major events in 2021 also included two wind storms that resulted in approximately five million customer minutes of outage.

43 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.

44 Newfoundland Power implemented a new Outage Management System in 2019. 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.

The Company maintains comprehensive policies and procedures which guide its approach to environmentally responsible operations. The Company set out an approach to emission reductions, including a target to reduce controlled greenhouse gas emissions by 55% by 2035, as compared to 2019 levels. The Company's Environmental Management System ("EMS") provides a framework for environmental management efforts and is critical to mitigating environmental risks.[45]

Certain of Newfoundland Power's assets contain substances that could be harmful if released into the environment.[46] The Company's asset maintenance standards and employee procedures are designed to prevent the release of these substances. Emergency preparedness tests are completed each year to confirm the effectiveness of prevention and response plans. In addition, employees are trained in best practices to perform immediate corrective action in the event of a release.

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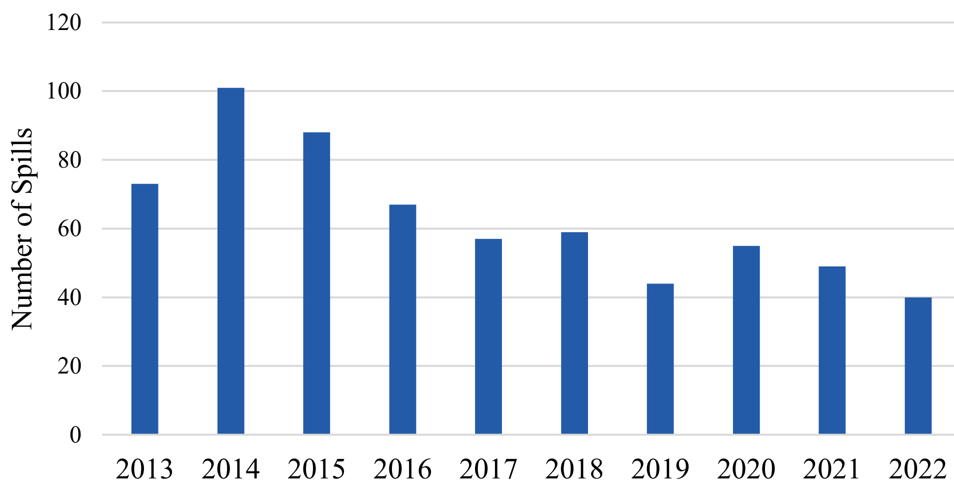
45 The EMS conforms to ISO 14001:2015 and is verified by a third-party auditor every two years.

46 The largest category of oil-filled equipment is transformers. The Company has approximately 66,000 oil-filled distribution transformers in its service territory, as well as a number of padmount transformers. Other oil-filled equipment includes breakers, reclosers, voltage regulators, metering tanks and vehicles.

Figure 2-10 shows the number of spills experienced by Newfoundland Power from 2013 to 2022.[47]

Figure 2-10:
Number of Spills by Year



The number of spills due to Company operations has declined since 2014, with 2022 being the lowest year for spills on record.

The Company manages its construction and maintenance activities to avoid harm to the province’s environment and support biodiversity. The Company complies with legislative requirements, including submitting Environmental Assessments to the Provincial Government for certain of the Company’s capital projects. In addition, the Company develops Environmental Protection Plans to manage the environmental impact of its construction activities.

[47] Figure 2-10 excludes all third-party spills and spills due to major events.

Environmental Assessments and Environmental Protection Plans ensure the Company manages its capital projects in an environmentally responsible manner. The plans may include scheduling construction to accommodate migratory bird season, or conducting environmental surveys to identify and protect vulnerable species.[48]

Newfoundland Power complies with regulatory requirements and industry standards designed to ensure protection of the environment. For example, the Government of Canada requires that all oil-filled equipment with polychlorinated biphenyl ("PCB") content greater than or equal to 50 parts per million be removed from operation by 2025.[49] The Company is executing a multi-year plan and is on track to meet this requirement. Newfoundland Power also follows an IEEE standard to construct spill containment for its oil-filled substation equipment to prevent ground contamination in the event of an oil leak.[50]

Additionally, the electricity generated by Newfoundland Power is over 99% hydroelectric. As a result, the Company's direct emissions are lower than utilities with larger thermal generating portfolios.

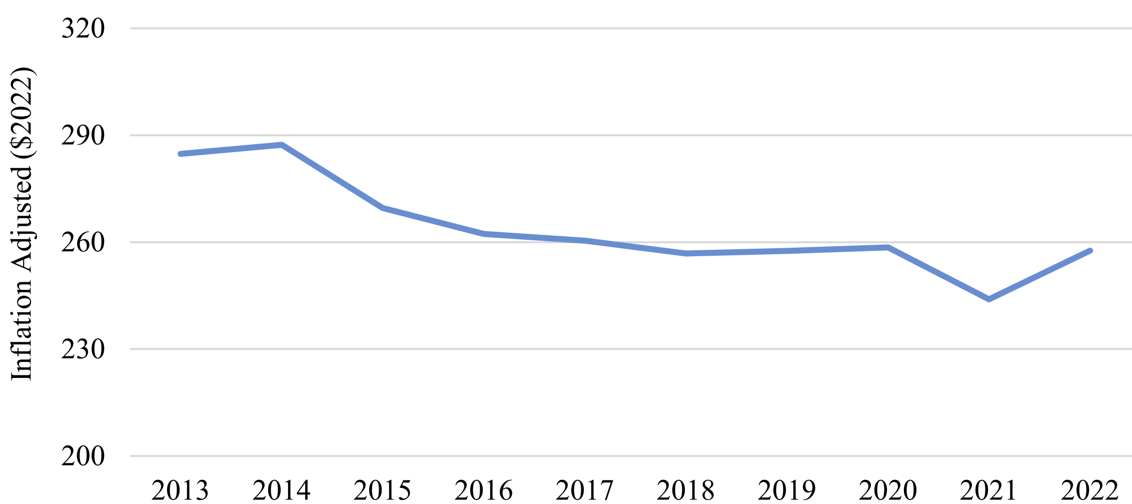
[48] For example, right-of-way clearing begins early in the year to limit disturbances to breeding birds.
[49] See *Government of Canada PCB Regulation (SOR/2008-273)*.
[50] IEEE Standard 980-2021 *Guide for Containment and Control of Oil Spills in Substations* recommends spill containment to prevent or mitigate the environmental impacts of an oil release or spill.

2.3.4 Operating Efficiency

Newfoundland Power provides service to its customers in an efficient manner. The Company's overall operating efficiency can be observed in the trending of its operating cost per customer over time.

Figure 2-11 shows Newfoundland Power's operating cost per customer from 2013 to 2022 on an inflation-adjusted basis.[51]

Figure 2-11:
Operating Cost per Customer
2013 to 2022



Newfoundland Power's operating efficiency has primarily been advanced over the last decade through the effective deployment of technologies.

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

Operating efficiencies over the last decade include those gained through the deployment of Automated Meter Reading ("AMR") meters, which can be read remotely.[52] Virtually all meters in Newfoundland Power's service territory were automated by year end 2017. The optimization of this technology has led to a reduction in meter reading routes, which allowed the Company to reduce its meter reading costs by nearly 80% from 2013 to 2022.[53]

Operating efficiencies are also gained through the enhancement of operations technologies. For example, the Company has expanded its Geographic Information System ("GIS") to provide accurate location-related information for electrical system assets, including street lights. Beginning in 2022, street light outages are tracked on a map to ensure accurate and precise analysis of required repairs or replacements. This eliminates approximately 1,000 duplicate reports of street light outages received from customers annually, which allows the Company to optimize its field operations.[54] Efficiencies are also realized through the automation of high-volume work tasks and the reduction or elimination of paper-based forms.[55]

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

[53] Newfoundland Power's meter reading costs were approximately $2.6 million in 2013, compared to approximately $541,000 in 2022 (($541,000 - $2.6 million) / $2.6 million = -0.79, or -79%).

[54] Newfoundland Power recorded a total of approximately 4,000 duplicate street light outage reports from 2018 to 2021.

[55] For example, application enhancements included in the Company's *2024 Capital Budget Application* provide for annual cost reductions of approximately $0.2 million. For more information, see Newfoundland Power's *2024 Capital Budget Application, Report 5.1: Application Enhancements.*

2.4 OPERATING AND CAPITAL COSTS

2.4.1 Operating Costs

General

Gross operating costs represent approximately 10% of Newfoundland Power's proposed 2026 revenue requirement from customer rates.[56]

Table 2-3 provides Newfoundland Power's gross operating costs from 2022 to 2026F.

Table 2-3:
Gross Operating Costs
2022 to 2026F
($000s)

2022	2023F	2024F	2025F	2026F
70,530	72,492	76,838	79,083	81,603

Gross operating costs are forecast to increase by $11.1 million from 2022 to 2026. This represents an annual increase in operating costs of approximately 3.9%, or $2.8 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 two ways: (i) by function as a customer service cost; and (ii) by breakdown as a labour cost.

[56] See *Volume 1, Application, Company Evidence and Exhibits, Exhibit 1 and Exhibit 7,* page 2 ($81,603,000 / $789,602,000 = 0.10, or 10%).

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 2-4 summarizes Newfoundland Power's operating costs by three functional categories from 2022 to 2026F: (i) electricity supply; (ii) customer services; and (iii) general.

Table 2-4:
Operating Costs by Function
2022 to 2026F
($000s)

Function	**2022**	**2023F**	**2024F**	**2025F**	**2026F**
Electricity Supply	31,578	31,730	32,690	33,794	34,876
Customer Services	10,681	11,177	11,319	11,700	12,074
General	28,271	29,585	32,829	33,589	34,653
Total	**70,530**	**72,492**	**76,838**	**79,083**	**81,603**

Table 2-5 shows operating costs associated with the electricity supply category by function from 2022 to 2026F.

Table 2-5:
Operating Costs – Electricity Supply
2022 to 2026F
($000s)

Function	**2022**	**2023F**	**2024F**	**2025F**	**2026F**
Distribution	11,295	10,755	11,102	11,500	11,919
Transmission	1,143	1,142	1,171	1,200	1,231
Substations	2,317	2,344	2,421	2,511	2,604
Power Produced	4,009	4,093	4,210	4,337	4,470
Administration and Engineering Support	8,929	9,429	9,700	10,054	10,425
Telecommunications	1,491	1,565	1,633	1,662	1,679
Environment	203	294	304	346	328
Fleet Operations and Maintenance	2,191	2,108	2,149	2,184	2,220
Total	**31,578**	**31,730**	**32,690**	**33,794**	**34,876**

Electricity supply costs for 2026 are forecast to increase by $3,298,000 compared to 2022. This represents an annual increase in electricity supply costs of approximately 2.6%, or $825,000 per year.

Higher forecast electricity supply costs reflect labour[57] and non-labour[58] inflationary increases over the 2022 to 2026 timeframe.

[57] The Company's internal weighted labour rate increases are 3.00% in 2022, 2.75% in 2023, 3.80% in 2024, 4.45% in 2025, and 4.50% in 2026. The 4.45% forecast increase in 2025 includes an estimated base wage increase of 3.70% and a 0.75% forecast progression. The 4.50% forecast increase in 2026 includes a 3.75% estimated base wage increase and a 0.75% forecast progression. On a compounded basis, the Company's weighted labour rate inflation is approximately 4.1% annually from 2022 to 2026. For information on Newfoundland Power's annual capital and operational work requirements over the 2024 to 2026 forecast period, see *Volume 2, Supporting Materials, Tab 1, Labour Forecast 2024-2026*.

[58] The Company forecasts its non-labour inflation using GDP deflators provided by the Conference Board of Canada.

Table 2-6 provides costs associated with the customer service category by function from 2022 to 2026F.

Table 2-6:
Operating Costs – Customer Services
2022 to 2026F
($000s)

Function	**2022**	**2023F**	**2024F**	**2025F**	**2026F**
Customer Service	8,069	8,259	8,305	8,605	8,919
Energy Solutions	585	873	828	873	897
Uncollectible Bills	2,027	2,045	2,186	2,222	2,258
Total	**10,681**	**11,177**	**11,319**	**11,700**	**12,074**

Customer service operating costs for 2026 are forecast to increase by $1,393,000 compared to 2022. This represents an annual increase in customer services costs of approximately 3.3%, or $348,000 per year.

Increased customer service costs reflect labour cost inflation, customer education and awareness initiatives planned over the period and increased uncollectible bills expense.

Table 2-7 provides costs associated with the general category by function from 2022 to 2026F.

Table 2-7:
Operating Costs – General
2022 to 2026F
($000s)

	2022	**2023F**	**2024F**	**2025F**	**2026F**
Information Systems	6,430	7,264	8,172	8,724	9,150
Financial Services	1,777	2,128	3,180	3,082	2,668
Corporate and Employee Services	17,850	17,765	18,856	19,010	19,903
Insurances	2,214	2,428	2,621	2,773	2,932
Total	**28,271**	**29,585**	**32,829**	**33,589**	**34,653**

General operating costs are forecast to increase by $6.4 million from 2022 to 2026. This represents an annual increase in general costs of approximately 5.6%, or $1,596,000 per year.

Higher information systems costs reflect an increase of approximately $2.1 million in licensing and support costs for third-party hardware and software solutions, including cybersecurity.[59]

Higher financial services costs reflect consultant costs associated with an upcoming change in accounting standards.[60] Higher corporate and employee costs reflect inflationary cost increases

[59] This includes increased costs of approximately: (i) $1,069,000 for operations and engineering software, such as the Outage Management System, GIS and the Asset Management System; (ii) $408,000 for infrastructure and network management; (iii) $378,000 for cybersecurity management; (iv) $150,000 for business back office software, such as the Financial Management System; and (v) $137,000 for customer service software, such as the new Customer Information System.

[60] The Ontario Securities Commission ("OSC") sets standards for financial reporting of publicly accountable enterprises. The OSC requires that financial statements be prepared in compliance with International Financial Reporting Standards ("IFRS"). Due to the absence of an IFRS standard that can appropriately account for rate-regulated activities, Newfoundland Power has been preparing its financial statements in accordance with United States of America generally accepted accounting principles ("U.S. GAAP") since 2012 under a series of exemptions granted by the OSC. An IFRS rate-regulated standard is expected to be published in 2024 with full implementation of IFRS required by 2027, at which time the Company's existing exemption will expire. An assessment is required to determine the financial reporting implications for Newfoundland Power of converting to IFRS.

and consultant costs associated with regulatory proceedings anticipated over the period. Higher insurance costs are due to increased premiums, which is consistent with 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).

Table 2-8 provides the breakdown of operating costs from 2022 to 2026F.

Table 2-8:
Operating Costs by Breakdown
2022 to 2026F
($000s)

	2022	**2023F**	**2024F**	**2025F**	**2026F**
Labour	39,037	38,992	40,429	42,079	43,882
Other	31,493	33,500	36,409	37,004	37,721
Total	**70,530**	**72,492**	**76,838**	**79,083**	**81,603**

Labour costs are forecast to make up approximately 54% of the Company's operating costs in 2026. Operating labour costs are an indicator of efficiency in Newfoundland Power's day-to-day operations.

Table 2-9 provides a breakdown of labour costs from 2022 to 2026F.

Table 2-9:
Labour Costs by Breakdown
2022 to 2026F
($000s)

	2022	**2023F**	**2024F**	**2025F**	**2026F**
Regular and Standby	34,794	34,820	36,099	37,557	39,156
Temporary	541	665	691	721	754
Overtime	3,702	3,507	3,639	3,801	3,972
Total	**39,037**	**38,992**	**40,429**	**42,079**	**43,882**

Newfoundland Power is forecasting an annual increase in labour costs of approximately 3.1% from 2022 to 2026.

The Company's weighted labour rate inflation is forecast to be approximately 4.1% per year over this period.[61] This implies an operating efficiency of approximately 1.0% per year.

Regular and standby labour costs are forecast to increase by $4.4 million from 2022 to 2026. This represents an annual increase of approximately 3.1%, or $1,091,000 through the period. The increase in regular and standby labour primarily reflects a combination of labour inflation and decreased labour costs associated with the enhancement of operation technologies.

Temporary labour costs are forecast to increase by $213,000 from 2022 to 2026. Temporary labour costs reflect an average of the required temporary labour over the last three years, adjusted for labour inflation.

[61] See footnote 57 for details on the Company's labour rate inflation.

Overtime labour costs are forecast to increase by $270,000 from 2022 to 2026. Overtime labour costs reflect an average of the amount of overtime labour required over the last three years, adjusted for labour inflation.

Other costs are forecast to make up approximately 46% of the Company's operating costs in 2026. 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 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 $6.2 million from 2022 to 2026. This represents an annual increase of approximately 4.9%, or $1,557,000, through the period. Increased other costs primarily reflect higher computing equipment and software costs, higher other company fees and inflationary increases.[62]

2.4.2 Capital Costs

Newfoundland Power's annual capital budgets reflect the expenditures necessary to provide customers with access to safe, reliable and environmentally responsible service at the lowest possible cost.

[62] From 2022 to 2026, computing equipment and software costs are forecast to increase by approximately $2.1 million and other company fees are forecast to increase by approximately $1.7 million.

Table 2-10 provides capital expenditures by asset class from 2022 to 2026F.[63]

Table 2-10:
Capital Expenditures by Asset Class
2022 to 2026F
($000s)

	2022[64]	**2023F**[65]	**2024F**	**2025F**	**2026F**
Distribution	50,434	53,671	55,865	55,033	56,938
Substations	14,196	20,720	22,171	20,824	23,299
Transmission	15,587	12,284	15,064	13,488	15,109
Generation	2,635	9,811	5,640	8,318	13,058
General Property	2,855	2,505	2,340	2,960	3,065
Transportation	3,089	4,968	3,806	4,867	4,839
Telecommunications	571	1,268	502	925	328
Information Systems	21,493	12,940	6,180	11,019	9,575
Total	**110,860**	**118,167**	**111,568**	**117,434**	**126,211**

Capital expenditures were approximately $111 million in 2022. Capital expenditures are forecast to increase to an average of $118 million annually from 2023 to 2026.

Increased capital expenditures over the forecast period are primarily observed in the Generation and Substation asset classes. Increased Generation capital expenditures reflect forecast requirements to refurbish existing hydro plants and replace Newfoundland Power's aging thermal units used for emergency backup purposes. Increased Substation capital expenditures

[63] Table 2-10 does not include the allowance for unforeseen items or general expenses capitalized. Forecast capital expenditures for 2024 through 2026 reflect the Company's *2024-2028 Capital Plan* included with Newfoundland Power's *2024 Capital Budget Application.* Capital expenditures for 2022 include expenditures related to approved projects that were completed in subsequent years.

[64] The Company's *2022 Capital Budget Application* was approved in Order No. P.U. 36 (2021).

[65] The Company's *2023 Capital Budget Application* was approved in Order No. P.U. 38 (2022). The *2023 Supplemental Capital Expenditure Application* was approved in Order No. P.U. 14 (2023).

reflect requirements to refurbish and modernize existing substations to replace obsolete and deteriorated equipment.

Capital expenditures are forecast to be reasonably stable across other asset classes. Distribution capital expenditures include the cost of connecting new customers and maintaining the distribution system, as well as the continued execution of the Company's multi-year *LED Street Lighting Replacement Plan*.[66] Transmission capital expenditures primarily reflect the continued execution of Newfoundland Power's long-term *Transmission Line Rebuild Strategy,* which targets the Company's oldest and most deteriorated transmission lines.

Information Systems capital expenditures are forecast to decline. The forecast decline is attributed to the conclusion of Newfoundland Power's multi-year *Customer Service System Replacement* project in 2023.[67]

Overall, Newfoundland Power's annual capital program continues to focus on the delivery of safe, reliable and environmentally responsible service to customers at the lowest possible cost.

[66] Capital expenditures related to the *LED Street Lighting Replacement Plan* are forecast to average approximately $5.5 million annually from 2021 to 2026.

[67] The replacement of the Company's Customer Service System was approved as a three-year multi-year project as part of Newfoundland Power's *2021 Capital Budget Application*.

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 required to maintain the financial integrity of the Company in 2025 and 2026 and are consistent with the fair return standard.

Expert evidence filed with this Application indicates a fair return for Newfoundland Power for 2025 and 2026 comprises: (i) a capital structure consisting of 45% common equity; and (ii) a return on equity of 9.85%. A 45% common equity component and a 9.85% rate of return on equity will maintain the Company's financial integrity and is consistent with the fair return standard.

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

The Application proposes changes to the Rate Stabilization Clause to allow for recovery of deferred electrification costs over 10 years, commencing January 1, 2025.

The Company proposes a change to the Demand Management Incentive ("DMI") Account definition to establish a threshold of ± $500,000. The proposed threshold will continue to provide an incentive to Newfoundland Power to minimize peak demand while recognizing the limitations the Company has in managing its demand costs. A threshold of ± $500,000 is consistent with prior approvals of the Board.

Newfoundland Power proposes to amortize $1 million in Board and Consumer Advocate costs in relation to this Application over a 30-month period. Cost differences from $1 million are proposed to be recovered or rebated through the Company's Rate Stabilization Account. Newfoundland Power also proposes to amortize a 2024 revenue shortfall of approximately $6.7 million and a 2025 revenue shortfall of approximately $16.8 million, both over a 30-month period.

Finally, the Company proposes to amend the Pension Capitalization Deferral Account to cease charges to the account effective December 31, 2024. Prior charges to the account will continue to be amortized over five years.

3.2 FINANCIAL PERFORMANCE: 2022 TO 2026

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 2024 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 2025 to 2026 period.

Exhibit 3 in Volume 1, Application, Company Evidence and Exhibits details Newfoundland Power's actual financial performance for 2022. Exhibit 3 also shows forecast financial performance for 2023 through 2026, excluding the proposals in this Application.

Exhibit 5 in Volume 1, Application, Company Evidence and Exhibits compares forecast financial performance for 2025 and 2026 based on existing customer rates and proposed rates, which incorporate the proposals in this Application.

The Company's financial forecasts under existing customer rates include the impact of the proposals in Newfoundland Power's 2024 Rate of Return on Rate Base Application filed with the Board on November 23, 2023.

3.2.1 Revenue

Energy Sales and Electricity Revenue

Table 3-1 shows energy sales and electricity revenue from 2022 to 2026E, excluding the proposals in this Application.[1]

Table 3-1:
Energy Sales and Electricity Revenue[2]
2022 to 2026E

	2022	**2023F**	**2024E**	**2025E**	**2026E**
Energy Sales					
Energy Sales (GWh)	5,784.5	5,949.2	5,981.4	6,034.1	6,026.3
Sales Change (%)	1.2	2.8	0.5	0.9	(0.1)
Electricity Revenue ($000s)					
Revenue from Rates	715,444	732,809	740,817	751,315	750,723
RSA Transfers	6,691	36,918	41,533	52,520	45,409
Excess Earnings Account[3]	-	(5,094)	-	-	-
Total Electricity Revenue	**722,135**	**764,633**	**782,350**	**803,835**	**796,132**

Increases in energy sales in 2022 and 2023 are due to higher new customer connections reflecting population growth experienced in that timeframe and higher average domestic and general service consumption. Energy sales are forecast to show modest growth over the 2024 to 2026 period reflecting low customer growth and government electrification initiatives partially offset by energy conservation and downward pressure on sales by increasing electricity rates.

[1] References to 2024 through 2026 with the suffix 'E' (e.g. 2024E) 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 2023F to 2026E are based on the Company's September 2023 sales forecast. The September 2023 *Customer, Energy and Demand Forecast* is found in *Volume 2, Supporting Materials, Tab 3.*

[3] See Section *3.2.7 Returns* for a discussion on the forecast Excess Earnings Account for 2023.

Other Revenue

Table 3-2 shows other revenue from 2022 to 2026E.

Table 3-2:
Other Revenue
2022 to 2026E
($000s)

	2022	2023F	2024E	2025E	2026E
Pole Attachment	2,483	2,545	2,585	2,622	2,660
Provisioning Work	2,086	1,579	1,270	1,015	1,027
Customer Account Interest	1,212	1,681	1,311	1,401	1,464
Interest on RSA	(1,667)	(24)	3,213	4,296	4,758
Wheeling Charges	765	723	719	705	704
Miscellaneous	1,241	918	928	980	1,033
Total	**6,120**	**7,422**	**10,026**	**11,019**	**11,646**

The Company's other revenue for 2022 was approximately $6.1 million. Other revenue is forecast to increase in 2023 through 2026 primarily due to higher interest charges associated with the Company's Rate Stabilization Account ("RSA") balances.[4]

[4] For example, the RSA had a debit balance of $3.9 million as of September 30, 2023. A debit balance reflects an amount owing from customers. The 2023 RSA balance is forecast to increase to $40.4 million by December 31, 2023 due to transfers from the Energy Supply Cost Variance Account.

3.2.2 Power Supply

Table 3-3 shows power supply costs from 2022 to 2026E.

Table 3-3:
Power Supply Costs
2022 to 2026E
($000s)

	2022	**2023F**	**2024E**	**2025E**	**2026E**
Purchases from Hydro (Normalized)	479,373	517,940	522,821	533,716	531,779
Demand Management Incentive Account	153	(1,000)	-	-	-
Power Supply Costs	**479,526**	**516,940**	**522,821**	**533,716**	**531,779**

Power supply costs are expected to increase by approximately $52.3 million from 2022 to 2026. The primary driver of the increase is higher purchased power requirements. Power supply costs reflect the wholesale purchased power rate effective October 1, 2019.[5]

3.2.3 Depreciation

Table 3-4 shows depreciation expense from 2022 to 2026E.

Table 3-4:
Depreciation Expense
2022 to 2026E
($000s)

	2022	**2023F**	**2024E**	**2025E**	**2026E**
Depreciation	70,662	74,869	79,557	83,143	86,691

Increases in depreciation expense over the period 2022 to 2026 are the result of the Company's annual capital investment in the electrical system.

[5] See Order No. P.U. 30 (2019). Current customer rates reflect an average supply cost rate of 6.940 ¢/kWh. The current second block rate is 18.165 ¢/kWh, which reflects the cost of production at Newfoundland and Labrador Hydro's Holyrood generating station.

Newfoundland Power's depreciation expense reflects the methodology and depreciation rates outlined in its *2019 Depreciation Study.*[6] The depreciation study and depreciation rates were approved by the Board during the *2022/2023 General Rate Application*.[7]

Newfoundland Power's depreciation rates are typically reviewed every four to five years.[8] The next depreciation study is expected to be completed in 2025 based on plant in service as of December 31, 2024.

3.2.4 Employee Future Benefits

General

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

Table 3-5 shows employee future benefits expense from 2022 to 2026E.

Table 3-5:
Employee Future Benefits Expense
2022 to 2026E
($000s)

	2022	**2023F**	**2024E**	**2025E**	**2026E**
Pension Expense	(63)	(4,006)	(3,886)	1,098	(1,824)
OPEB Expense	7,715	6,769	6,896	7,024	3,636
Total Expense	**7,652**	**2,763**	**3,010**	**8,122**	**1,812**

6 The Gannett Fleming *2019 Depreciation Study* was filed in *Volume 3, Expert Evidence, Tab 1*, as part of the Company's *2022/2023 General Rate Application*.
7 See Order No. P.U. 3 (2022), pages 12 and 13.
8 The Company's previous five depreciation studies were completed for plant in service at December 31, 2001, 2005, 2010, 2014 and 2019.

Newfoundland Power expects total employee future benefits expense to decrease by approximately $5.8 million from 2022 to 2026.

Pensions

Newfoundland Power maintains both defined benefit and defined contribution pension plans. The Company's defined benefit pension plan has been closed to new entrants since 2004.[9] 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 3-6 shows the components of Newfoundland Power's pension expense from 2022 to 2026E.

Table 3-6:
Pension Expense
2022 to 2026E
($000s)

	2022	**2023F**	**2024E**	**2025E**	**2026E**
Defined Contribution Pension Plan	3,061	1,663	1,877	2,117	2,306
Defined Benefit Pension Plan	(3,124)	(5,669)	(5,763)	(1,019)	(4,130)
Total Pension Expense	**(63)**	**(4,006)**	**(3,886)**	**1,098**	**(1,824)**

Newfoundland Power expects defined contribution pension plan expense to decrease by approximately $0.8 million from 2022 to 2026 reflecting changes in pension capitalization

[9] Newfoundland Power's defined benefit pension plan was created in 1984 and closed to new entrants in 2004. There were 162 active employees participating in this plan as at December 31, 2022. In addition, at December 31, 2022, the defined benefit pension plan provided retirement income to a total of 787 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.

effective January 1, 2023.[10] The decrease is partially offset by an increased number of employees, increases in employer matching rates and increases in compensation.[11]

Defined benefit pension plan expense reflects: (i) the results of the Company's latest actuarial pension funding valuation;[12] (ii) returns on plan assets to 2022;[13] and (iii) variations in the forecast discount rates provided by actuaries.[14] Defined benefit pension expense is forecast to decrease by approximately $1.0 million between 2022 and 2026. The decline primarily reflects changes in pension capitalization.[15]

OPEB

Table 3-7 shows OPEB expense from 2022 to 2026E.

Table 3-7:
OPEB Expense
2022 to 2026E
($000s)

	2022	**2023F**	**2024E**	**2025E**	**2026E**
OPEB Expense	7,715	6,769	6,896	7,024	3,636

10 In Order No. P.U. 3 (2022), the Board approved revisions to Newfoundland Power's General Expenses Capitalized ("GEC") calculation effective January 1, 2023. These revisions included a change in capitalizing pension costs from the indirect method via GEC to the direct method via a labour loader. This results in a more accurate allocation of general expenses to capital.

11 Employer contributions are forecast to increase from 6.50% to 6.75% effective January 1, 2024, and to 7.00% effective January 1, 2025.

12 The Company typically completes an actuarial pension funding valuation every three years. The latest valuation was completed as at December 31, 2022.

13 In 2022, the expected return on defined benefit pension plan assets was 4.50%. Expected returns are 5.75% for 2023 through 2026.

14 In 2022, the discount rate used for expense projections was 3.20%. A discount rate of 5.30% is forecast for 2023 and 4.80% is forecast for 2024 through 2026.

15 See footnote 10.

OPEB expense is forecast to decrease by approximately $4.1 million between 2022 and 2026. This reflects: (i) full amortization of the transitional obligation associated with the Company's adoption of the accrual method of accounting for OPEB costs by December 31, 2025;[16] and (ii) a higher forecast discount rate.[17]

3.2.5 Finance Charges

Table 3-8 shows average debt, finance charges and average cost of debt from 2022 to 2026E.[18]

Table 3-8:
Finance Charges
2022 to 2026E

	2022	2023F	2024E	2025E	2026E
Average Debt ($000s)	661,762	728,164	789,314	826,322	868,798
Average Cost of Debt (%)	5.25	5.11	5.26	5.10	4.99
Finance Charges ($000s)	34,767	37,241	41,534	42,166	43,353

Newfoundland Power's average debt is expected to increase by approximately $207 million from 2022 to 2026. The increase in average debt is primarily to finance capital expenditures necessary to maintain system reliability and to provide required service to customers.[19] The Company's average cost of debt from 2022 to 2026 is expected to decline by 0.26%. This primarily reflects

[16] The Company adopted, for regulatory purposes, the accrual method of accounting for OPEB costs effective January 1, 2011. The adoption of the accrual method of accounting for OPEB costs resulted in a transitional obligation of $52.4 million at the end of 2010. In Order No. P.U. 31 (2010), the Board approved Newfoundland Power to amortize the transitional obligation using the straight-line method over a 15-year term.

[17] In 2022, the discount rate used for expense projections was 3.20%. A discount rate of 5.30% is forecast for 2023 through 2026.

[18] Table 3-8 shows regulated finance charges, which exclude interest on security deposits as they are not included in the determination of revenue requirements.

[19] Newfoundland Power's annual capital expenditures for the period 2022 through 2023 were approved by the Board in Order Nos. P.U. 10 (2021), P.U. 12 (2021), P.U. 30 (2021), P.U. 36 (2021), P.U. 38 (2022), and P.U. 14 (2023). The Company's *2024 Capital Budget Application* is currently under review by the Board.

lower average coupon rates on the Company's first mortgage bonds.[20]

Newfoundland Power's finance charges are expected to increase by approximately $8.6 million from 2022 to 2026. The increase primarily reflects higher interest on long-term debt, higher short-term borrowing costs and lower Allowance for Funds Used During Construction ("AFUDC") associated with the completion of the Customer Service System Replacement Project in 2023.

3.2.6 Income Taxes

Table 3-9 shows income taxes from 2022 to 2026E.

Table 3-9:
Income Taxes
2022 to 2026E

	2022	**2023F**	**2024E**	**2025E**	**2026E**
Income Taxes ($000s)	19,498	20,020	22,399	20,037	18,010
Effective Income Tax Rate (%)[21]	28.9	29.7	30.4	30.5	30.3

Newfoundland Power's effective income tax rate is forecast to remain relatively stable through the 2022 to 2026 period.

[20] This is a result of higher interest rate debt being retired and replaced with lower interest rate debt. For example, in June 2022, Newfoundland Power repaid $28.4 million associated with the maturity of 10.125% Series AF First Mortgage Bonds. In August 2023, the Company issued $90 million in 5.122% Series AS First Mortgage Bonds.

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

3.2.7 Returns

Table 3-10 shows the approved, actual and forecast rates of return on rate base, and the actual and forecast rates of return on common equity from 2022 to 2026E.

Table 3-10:
Rates of Return
2022 to 2026E
(%)

	2022	2023F	2024E	2025E	2026E
Return on Rate Base					
Midpoint (Approved/Proposed)	6.61	6.39	6.85	-	-
Actual / Forecast	6.72	6.85	6.82	6.24	5.84
Return on Common Equity	8.95	8.44	8.44	7.16	6.38

Newfoundland Power's rate of return on rate base was within the range approved by the Board for 2022 and is forecast to be above the approved range for 2023, driven by a higher forecast return on debt compared to the Company's 2023 test year return on debt.[22] The increased 2023 return on debt since existing customer rates were established in March 2022 reflects increases in the Bank of Canada's benchmark interest rate over that timeframe. From March 2022 to July 2023, the Bank of Canada increased its interest rate 10 times for a total increase of 4.75%. Any return on rate base amounts in excess of the +0.18% range approved by the Board are credited to

[22] In Order No. P.U. 3 (2022), the Board approved a rate of return on rate base for 2022 of 6.61% in a range of 6.43% to 6.79%, and the rate of return on rate base for 2023 of 6.39% in a range of 6.21% to 6.57%. For 2023, the Company forecasts to be outside of the range by 28 basis points. The Company's 2023 forecast weighted average cost of debt is 2.88%, which is 31 basis points higher than the 2023 test year weighted average cost of debt of 2.57%.

the Company's excess earnings account.[23] Excess earnings, on an after-tax basis, are forecast to be \$3.6 million in 2023.[24]

Newfoundland Power's forecast rate of return on rate base for 2024 is within the ±0.18% basis point range proposed by the Company in its *2024 Rate of Return on Rate Base Application*. The forecast rates of return on rate base and rates of return on equity for 2025 and 2026 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 two independent rating agencies: DBRS Morningstar ("DBRS") and Moody's Investors Service ("Moody's").[25] 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

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[23] Any excess earnings for 2023 will be transferred to the Excess Earnings Account on December 31, 2023. The Excess Earnings Account definition provides that the disposition of any balance in the account shall be determined by the Board. As part of Newfoundland Power's *2016/2017 General Rate Application*, excess earnings from 2013 were used to lower the Company's 2016 revenue requirement. See Schedule 1, Appendix E, page 1, line 17 of Newfoundland Power's compliance application filed with the Board on June 17, 2016 in relation to its *2016/2017 General Rate Application*.

[24] The 2023 excess earnings after-tax amount of \$3.6 million translates to \$5.1 million on a revenue requirement basis (i.e. before tax).

[25] 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.'

regulatory framework (25%) and the ability to recover costs and earn returns (25%).[26] Similarly, DBRS considers Newfoundland Power's stable and supportive regulatory environment and strong financial profile as key credit strengths.[27]

Table 3-11 shows Newfoundland Power's credit metrics from 2022 to 2026E.[28]

Table 3-11:
Credit Metrics
2022 to 2026E

	2022	**2023F**	**2024E**	**2025E**	**2026E**
Pre-tax Interest Coverage (times)	2.5	2.4	2.4	2.2	2.0
Cash Flow Interest Coverage (times)[29]	4.4	3.6	2.9	2.9	2.8
Cash Flow Debt Coverage (%)[30]	17.4	12.9	10.2	9.6	9.0

Under existing customer rates, Newfoundland Power's pre-tax interest coverage is expected to decline from 2.5 times in 2022 to 2.0 times in 2026, reflecting the deterioration of the Company's pre-tax earnings over that time period. This has implications for Newfoundland Power's future financing flexibility.

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[26] See Exhibit 4 in *Volume 1, Application, Company Evidence and Exhibits, Moody's,* page 9.
[27] See Exhibit 4 in *Volume 1, Application, Company Evidence and Exhibits, DBRS,* page 2.
[28] Cash flow metrics from 2022 to 2026 are negatively impacted by the combination of the current wholesale rate charged by Hydro and an increase in energy sales. Additional energy requirements are purchased from Hydro at a second block rate of 18.165 ¢/kWh. This is substantially higher than additional sales revenue, which reflects an average supply cost rate of 6.940 ¢/kWh. This dynamic results in a negative impact on operating cash flow pre-working capital. Ultimately, any additional costs are collected from customers via the Company's Energy Supply Cost Variance Clause. This dynamic is temporary as it is anticipated that the second block rate will be substantially lower following Hydro's next GRA, reflecting commissioning of the Muskrat Falls Project.
[29] Excluding the impact of current energy supply cost variances, Newfoundland Power's cash flow interest coverage would be 4.4 times in 2023, 3.8 times in 2024, 3.9 times in 2025, and 3.7 times in 2026.
[30] Excluding the impact of current energy supply cost variances, the Company's cash flow debt coverage would be 17.1% in 2023, 14.7% in 2024, 14.6% in 2025, and 13.6% in 2026.

The Deed of Trust and Mortgage (the "Trust Deed") that secures the Company's 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").[31] Based on 2025 and 2026 pre-tax earnings, Newfoundland Power's Bond Earnings Test would be 2.1 and 1.9 times, respectively. Under existing customer rates, the Company would have limited flexibility to issue first mortgage bonds by 2026.

Under existing customer rates, Newfoundland Power's cash flow metrics are also forecast to decline from 2022 to 2026. This financial outlook, combined with the Company's business risk, can affect Newfoundland Power'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 2025 and 2026. The expert evidence filed with this Application indicates a fair return for Newfoundland Power for 2025 and 2026 comprises: (i) a capital structure consisting of 45% common equity; and (ii) a return on equity of 9.85%.

The Board typically reviews Newfoundland Power's cost of capital every three years. In determining a fair return, the Board has applied principles prescribed by the Electrical Power

[31] Article 6.2 of the Trust Deed 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."*

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 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 are largely consistent with those outlined in the Company's 2022/2023 General Rate Application. This section of evidence also reviews Newfoundland Power's credit metrics under the Company's existing scenario and with the proposals contained in this Application. The proposals in this Application, which include a return on equity of 9.85% for 2025 and 2026 based on a capital structure with a target equity ratio of 45%, are consistent with the fair return standard.

The use of the Automatic Adjustment Formula (the "Formula") has been suspended by the Board since 2011. Current financial market conditions are volatile and do not support adoption of a formula that can reliably estimate Newfoundland Power's return on equity between test years. The Company, therefore, proposes continued suspension of the Formula. The expert evidence filed with this Application recommends continued suspension of the 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 at the lowest possible cost and in an environmentally responsible manner.

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.[32] 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 on prime lending rates. Interest on long-term debt is determined by capital markets at the time the debt is issued.

[32] 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.

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.[33]

Newfoundland Power as a debt issuer, and its long-term debt, have held investment-grade ratings from two credit rating agencies for over 25 years. 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 the *Electrical Power Control Act*, *1994* and the *Public Utilities Act*. The legislative construct for Newfoundland Power is broadly consistent with those applicable to 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."*

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[33] 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 nine-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."* See Moody's Investors Service, *Rating Symbols and Definitions*, December 20, 2022.

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."*[34]

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."*[35]

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

The Board's view of the fair return standard is one that is 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 two decades and has 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.[36]

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."*[37]

The Board's views of the appropriateness of Newfoundland Power's longstanding capital structure have remained consistent since it was first approved in 1996.

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

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."*[38]

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.[39]

Newfoundland Power's capital structure formed part of the settlement agreement reached in relation to the Company's *2019/2020 General Rate Application.*[40] 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."*[41]

Newfoundland Power's capital structure also formed part of the settlement agreement reached in relation to the Company's *2022/2023 General Rate Application*.[42]

[38] See Order No. P.U. 19 (2003), page 45.
[39] See Order No. P.U. 18 (2016), page 25, lines 14-15.
[40] See Order No. P.U. 2 (2019), page 12, lines 20-27.
[41] See Order No. P.U. 2 (2019), page 12, lines 20-22.
[42] See Order No. P.U. 3 (2022), page 4, lines 13-16.

In Order No. P.U. 3 (2022), the Board stated:

> *"The Board notes that Newfoundland Power has maintained a solid financial profile and investment grade credit rating from both Moody's Investor Service ("Moody's") and DBRS Morningstar ("DBRS") and this has contributed to continued access to capital markets on reasonable terms…Both Moody's and DBRS recognize Newfoundland Power's longstanding 45% common equity component as a key credit strength."*[43]

3.3.2 Risk Assessment

General

Newfoundland Power's cost of capital is the rate of return that 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.

Newfoundland Power's business risks in 2023 remain largely consistent with those described in 2021 during the Company's *2022/2023 General Rate Application*. The Company's business risks continue to be defined by longstanding factors, including weak service territory demographics, a harsh operating environment, the Company's small size and limited cost flexibility. The provincial economic outlook remains weak, with economic indicators that continue to lag behind the rest of Canada. The Muskrat Falls Project continues to pose a risk to the least-cost delivery of reliable service to customers.

Provincial Economy

The economic outlook for Newfoundland and Labrador is expected to remain weak in comparison to the rest of Canada over the medium term.

[43] See Order No. P.U. 3 (2022), page 5, lines 10-16.

Table 3-12 compares the economic outlooks for Newfoundland and Labrador and Canada from 2023 to 2027.

Table 3-12:
Economic Outlook
Newfoundland and Labrador vs. Canada
2023 to 2027[44]

Economic Indicator	NL	Canada	Difference
GDP	1.5%	1.9%	-0.4%
Labour Force	-0.1%	1.4%	-1.5%
Employment	-0.3%	1.3%	-1.6%
Household Disposable Income	1.5%	3.3%	-1.8%
Retail Sales	1.1%	2.8%	-1.7%
Housing Starts	-14.7%	-0.3%	-14.4%

The economic outlook for Newfoundland and Labrador lags behind that of Canada across all key economic indicators over the 2023 to 2027 period.

Newfoundland and Labrador's economy shrank by 1.3% in 2022 and was the only province whose economy contracted.[45] While Provincial GDP growth is expected to improve, it is expected to lag the national GDP growth forecast over the same period.

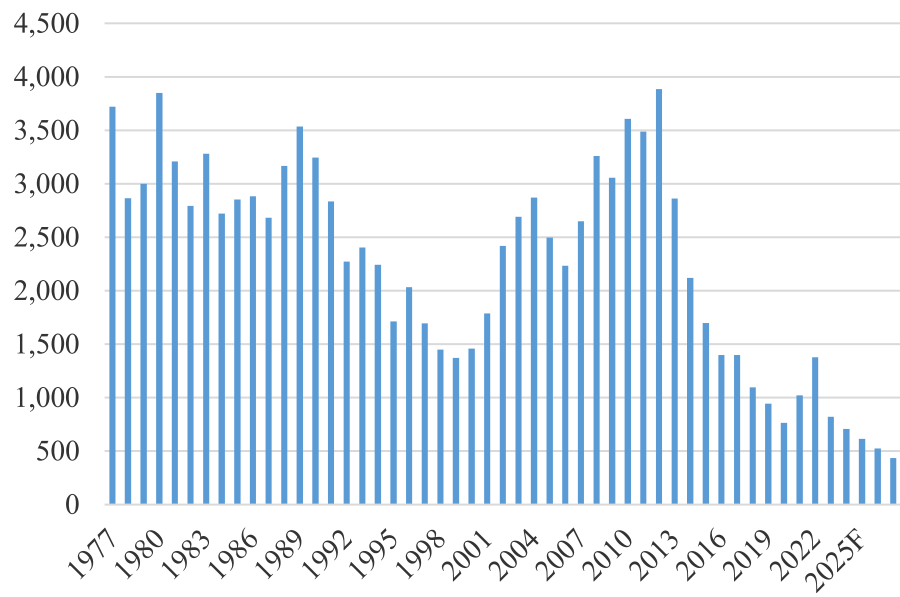
Housing starts in Newfoundland and Labrador have declined since reaching a historic peak of 3,885 in 2012.

44 Based on The Conference Board of Canada medium-term outlook published August, 2023. See *Volume 2, Supporting Materials, Tab 3, Customer Energy and Demand Forecast, Attachment 1*.

45 See The Conference Board of Canada *Economic Recovery Delayed as Growth Stalls – Newfoundland and Labrador's Three-Year Outlook,* September 6, 2023, Page 6.

Figure 3-1 shows housing starts in Newfoundland and Labrador since 1977.[46]

Figure 3-1:
Newfoundland and Labrador Housing Starts
1977 – 2027F



Following modest increases in 2021 and 2022, housing starts are forecast to return to a declining trend in 2023.[47] Forecast housing starts are 434 in 2027, or just 11% of 2012 housing starts. The number of housing starts expected in the forecast period are the lowest observed by Newfoundland Power since at least 1977.

The Conference Board of Canada observes recent improvement in the provincial economy and acknowledges challenges facing Newfoundland and Labrador's economy in the years ahead.

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[46] Newfoundland Power's historical housing starts statistics date back to 1977.

[47] Housing starts increased modestly in 2021 and 2022 following the gradual easing of public health measures related to the COVID-19 pandemic. Housing starts in 2020, 2021, and 2022 were 763, 1,021, and 1,379, respectively.

> *"The post-pandemic resurgence in economic activity and record-level population gains have supported robust employment and labour force growth in Newfoundland and Labrador since 2021. The province added over 9,600 jobs in 2022, an increase of 4.3 per cent. At the same time, the labour force grew by 2.1 percent. However, these gains are untenable given that population growth is expected to reverse course and return to a prolonged period of losses starting in 2025."*[48]

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

Provincial demographics are defined by an aging population, low fertility rates and out-migration to other Canadian provinces. Recent immigration from persons outside Canada has helped mitigate provincial population decline in 2022 and 2023. However, Newfoundland and Labrador's demographics continue to be weaker than the rest of Canada.

Newfoundland and Labrador's population is older than the Canadian population. In 2021, the median age of the Canadian population was 41.6 years, whereas the median age of the Newfoundland and Labrador population was 48.4 years, almost 7 years older.[49] The difference in population age between Newfoundland and Labrador and the rest of Canada has increased over time.[50]

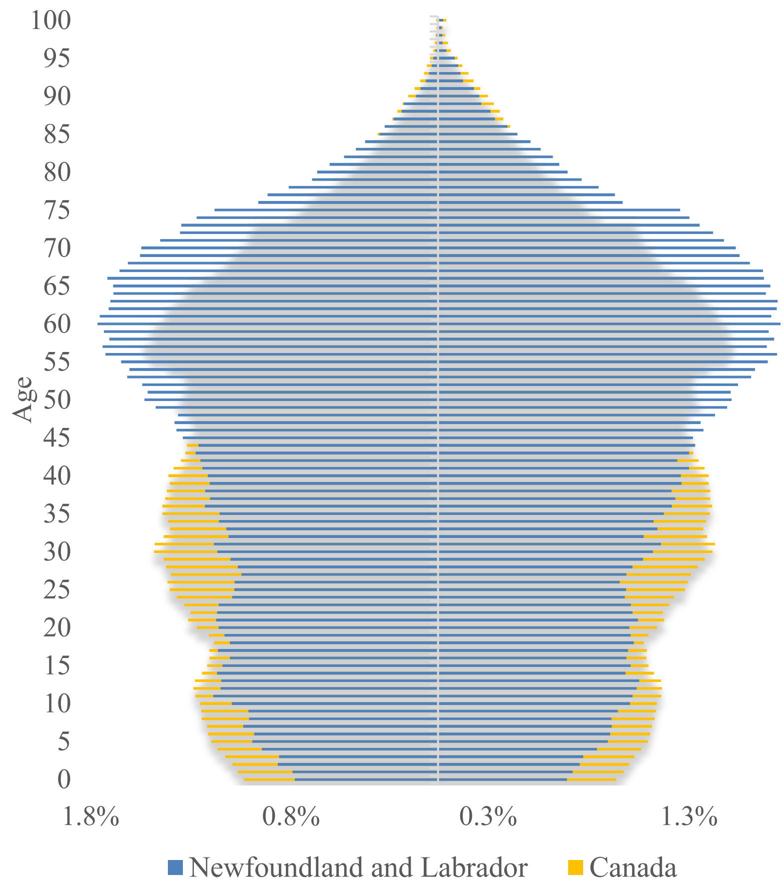
48 See The Conference Board of Canada *Economic Recovery Delayed as Growth Stalls – Newfoundland and Labrador's Three-Year Outlook*, September 6, 2023, page 7.

49 See Statistics Canada *Comparison Age and Gender Pyramid*, Release Date April 27, 2022.

50 For example, in 1999 the median age of the Canadian and Newfoundland and Labrador populations was approximately equal. The median age of the Canadian population was 36.6 years while the median age of the Newfoundland and Labrador population was 36.7 years.

1 Figure 3-2 shows the population pyramids of both Newfoundland and Labrador and Canada.

Figure 3-2:
Population Pyramid[51]
Newfoundland and Labrador vs. Canada
2021



2 The population pyramid of Newfoundland and Labrador shows a relatively high concentration of
3 residents between 50 and 70 years of age compared to younger cohorts. The population pyramid
4 of Canada shows a more uniform distribution of age cohorts. This demonstrates the
5 disproportionate number of older residents in Newfoundland and Labrador as compared to the
6 rest of Canada.

[51] See Statistics Canada *Comparison Age and Gender Pyramid*, Release Date April 27, 2022.

Newfoundland and Labrador's low fertility rates combined with increasing population mortality contributes to a natural population decline. Newfoundland and Labrador's total fertility rate continues to be below the replacement rate required over the long term to maintain current population levels in the absence of migration.[52] In 2022, there were 3,850 births in Newfoundland and Labrador. By comparison, there were 6,100 deaths in 2022 leading to a natural population decline. The negative natural population decline is expected to become progressively larger in the future.[53]

The population of Newfoundland and Labrador increased by 1.3% from July 1, 2022 to July 1, 2023. The population increase was the result of international and interprovincial migration, partially offset by losses due to natural population decline. The population of Canada grew by 2.9% over the same period.[54]

The demographic challenges faced by the Province are recognized by the Conference Board of Canada. In its most recent long-term outlook the Conference Board of Canada states:

> *"A poor demographic outlook will be the primary reason behind slow economic growth. We expect Newfoundland and Labrador's population to start dropping again after the next two years and keep falling throughout the forecast period, shrinking from around 525,000 to 463,500 between 2022 and 2045 – a decline of almost 12 per cent. While we project net international migration will be elevated relative to the last decade, this increase will be offset by a continued outflow of workers to other provinces and a decreasing natural rate of change (birth rate minus death rate). Population aging will*

[52] Newfoundland and Labrador's total fertility rate was 1.36 children per child-bearing age woman in 2021. The replacement rate required long term to maintain current population levels in the absence of migration is 2.1 children per child-bearing age woman. See Government of Newfoundland and Labrador, *Population Projections – Demographic Overview*, May 2023.

[53] The Government of Newfoundland and Labrador projects that deaths will exceed births by approximately 4,300 by 2042, compared to approximately 2,300 more deaths than births in 2022. See Government of Newfoundland and Labrador *Population Projections – Demographic Overview*, May 2023.

[54] See Government of Newfoundland and Labrador, Department of Finance Population Bulletin, September 27, 2023.

> *also shift spending patterns. The healthcare sector will come under greater pressure from the aging and declining population. A low workforce participation rate averaging 54.0 per cent over the long term will also strain household spending and government finances."*[55]

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

The population of the Northeast Avalon increased by 7% over the period 2012 to 2022. This compares to a 5% decline in population for the remainder of the province over the same period.[56]

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 15% by 2042. The population outside of the Northeast Avalon is projected to decline by 5%.[57]

In 2022, one quarter of Newfoundland Power's distribution assets were located on the Northeast Avalon, which is expected to continue to experience population growth. The remaining three quarters of distribution assets served customers in more rural areas of the province that are expected to experience population decline.

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.

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[55] See The Conference Board of Canada *Demographic Troubles and Opportunities in Energy – Newfoundland and Labrador's Outlook to 2045*, February 22, 2023, page 4.

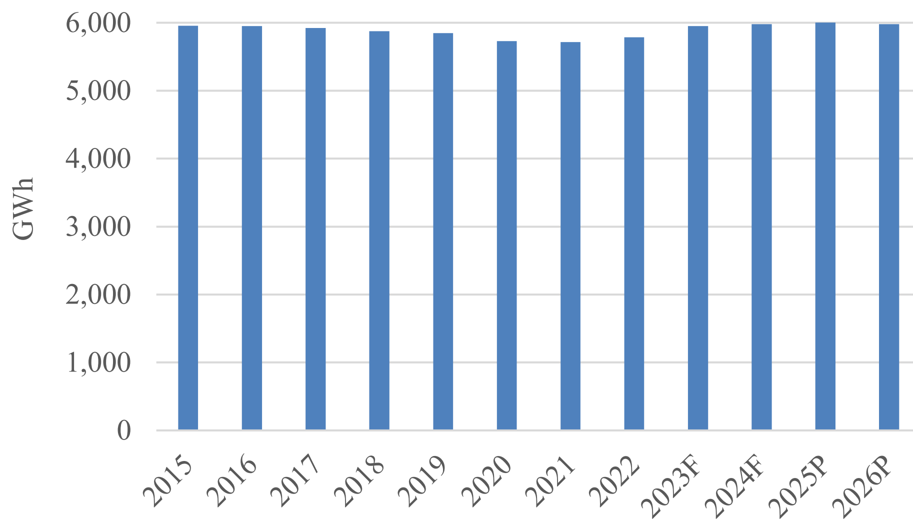
[56] See Statistics Canada, Tables 17-10-0135-01 and 17-10-0139-01, January 11, 2023.

[57] See Government of Newfoundland and Labrador *Population Projections – Demographic Overview,* May 2023.

Energy Sales

Figure 3-3 shows Newfoundland Power's annual energy sales for the period 2015 to 2026P.

Figure 3-3:
Energy Sales
2015 – 2026P



Newfoundland Power experienced declining energy sales each year from 2016 to 2021. In 2022, the Company's annual energy sales increased for the first time since 2015. The increase in Newfoundland Power's energy sales was attributable to higher General Service energy consumption following the COVID-19 pandemic, recent population growth and electrification trends, including customer conversions from oil to electric space heating and new customer end uses, such as electric vehicles. Newfoundland Power anticipates these trends to continue in the near term, particularly as it relates to customer electrification trends. However, sales growth is expected to be tempered by increasing electricity rates, a weak economic outlook, conservation and demand management activities, and medium to long-term population decline.

The relatively low forecast growth of Newfoundland Power's energy sales during the 2023 to 2026 period reflects a mixture of positive and negative factors. Low energy sales growth makes the Company less appealing to financial markets than utilities with higher growth potential.

Muskrat Falls and Electricity Supply

Newfoundland Power is dependent upon Hydro for the bulk generation and transmission of electricity to customers.[58] The cost of electricity supply from Hydro directly affects the cost of providing service to customers.[59] Reliability of supply from Hydro also directly affects reliability of service for Newfoundland Power's customers.

The electricity supply outlook continues to be challenged by factors associated with the Muskrat Falls Project.[60] This includes both costs and reliability.

In April 2023, the Muskrat Falls Project was considered fully commissioned.[61] Since commissioning, Hydro has been required to pay monthly costs associated with all Muskrat Falls Project agreements.[62]

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58 Newfoundland Power purchases approximately 93% of its energy requirements from Hydro.

59 The cost of electricity supply from Hydro is Newfoundland Power's single largest cost and represents approximately two-thirds of Newfoundland Power's cost of providing service to customers.

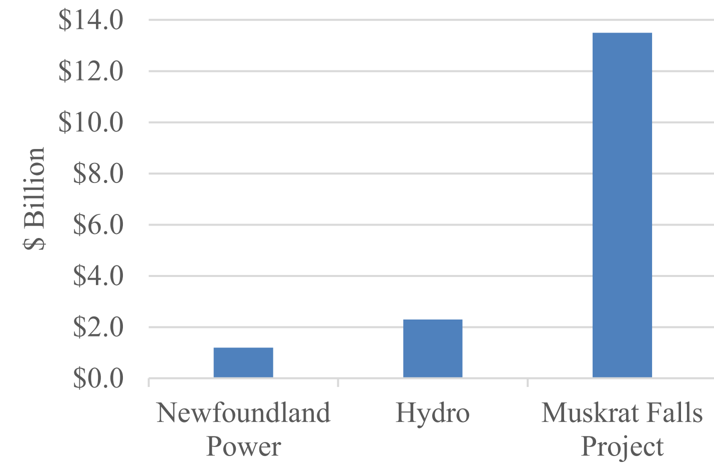
60 The Muskrat Falls Project consists of: (i) the Muskrat Falls generating facility; (ii) the Labrador Transmission Assets between Muskrat Falls and Churchill Falls; (iii) the Labrador-Island Link (the "LIL") transmission line; and (iv) the Maritime Link between the island of Newfoundland and Nova Scotia.

61 See Hydro's April 18, 2023 letter *Re: Reliability and Resource Adequacy Study Review – Labrador-Island Link Update.*

62 Hydro is required to make payments under the Muskrat Falls Power Purchase Agreement and the Transmission Funding Agreement.

The final cost of the Muskrat Falls Project is $13.5 billion.[63] Figure 3-4 shows the cost of the Muskrat Falls Project in comparison to the net book value of the utility investment of Newfoundland Power and Hydro in 2022.

Figure 3-4:
Electricity System Assets
2022



The net book value of Newfoundland Power's utility assets is approximately $1.2 billion, while the net book value of Hydro's regulated utility assets is approximately $2.3 billion. The cost of the Muskrat Falls Project is almost four times the combined book value of the current utility investment of Hydro and Newfoundland Power. Recovery of this investment increases cost pressure for customers on the Island Interconnected System.[64]

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63 See CBC News, *Muskrat Falls generating unit must be fully dismantled, says report*, July 12, 2023.

64 Newfoundland Power's average rate base at year-end 2022 was approximately $1.2 billion as shown in Return 3 of Newfoundland Power's *2022 Annual Report* filed with the Board on March 31, 2023. Hydro's average rate base at year-end 2022 was approximately $2.3 billion, as shown in Return 3 of Hydro's *2022 Annual Return* filed with the Board on March 31, 2023. ($13.5 billion / ($1.2 billion + $2.3 billion) = 3.9).

In 2022, Hydro introduced its Project Cost Recovery Rider to begin to recover costs associated with the Muskrat Falls Project from customers.[65] The Project Cost Recovery Rider currently recovers a small portion of Muskrat Falls Project costs from customers.[66] Recovery of additional costs from customers is dependent on the finalization of the Provincial Government's Rate Mitigation Plan and an order from the Board approving Hydro's next general rate application.[67]

The outlook for electricity supply on the Island Interconnected System changed materially in 2022 with Hydro's latest update to its Reliability and Resource Adequacy Study (the "2022 Update").[68] The change is largely due to lower reliability assumptions for the LIL and the subsequent need to maintain backup generation in the event of a LIL outage.

Hydro's 2022 Update recommends extending the operation of the 490 MW Holyrood Thermal Generating Station ("Holyrood") and 50 MW Hardwoods Gas Turbine ("Hardwoods") until 2030, or until such time that sufficient alternative generation is commissioned and Holyrood and Hardwoods are no longer required.[69] Continuing to operate Holyrood until 2030 is expected to cost approximately $150 million annually, and total approximately $1 billion between 2024 and

[65] Hydro's Project Cost Recovery Rider was approved by the Board in Order No. P.U. 19 (2022).

[66] For the month of September 2023, Hydro recorded approximately $60.9 million in deferred costs associated with the Muskrat Falls Project and recovery of approximately $2.5 million from customers through the Project Cost Recovery Rider. See Hydro's *Supply Cost Variance Deferral Account Monthly Report, September 2023* which was filed with the Board on October 24, 2023.

[67] On February 14, 2022, as part of the Province's Rate Mitigation Plan, Hydro, the Province and the Government of Canada agreed to a $1 billion federal loan guarantee, capital restructuring of the Muskrat Falls Project, and a $1 billion investment by the Government of Canada in the LIL. The Provincial Government has not finalized all aspects of its rate mitigation plan. In its September 29, 2023 letter *Re: Quarterly Update – Items Impacting the Delay of Hydro's Next General Rate Application*, Hydro provided that it expects the earliest timeframe for its next general rate application to be the latter half of 2024.

[68] Hydro filed its *Reliability and Resource Adequacy Study – 2022 Update* with the Board on October 3, 2022.

[69] See Hydro's 2022 Update, Volume III: Long-Term Resource Plan, Page 27, Lines 7-10.

2030, in addition to unanticipated costs.[70] The reliable operation of Holyrood cannot be assured.[71]

Hydro's 2022 Update also recommends construction of new sources of capacity on the Island Interconnected System. Hydro recommends construction of a 154 MW expansion to its Bay d'Espoir hydroelectric facility ("Unit 8") with an estimated cost of $522 million to serve as a long-term backup facility and to support forecast load growth over the longer-term.[72] Hydro is also evaluating alternative sources of backup generation to replace Holyrood and Hardwoods in the coming years.[73]

Further details regarding capacity additions on the Island Interconnected System are expected in the near to medium term as part of the Board's Reliability and Resource Adequacy Study Review.[74] Hydro's next Resource Adequacy Plan is expected to be filed with the Board in the spring of 2024.[75]

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[70] See Hydro's 2022 Update, Volume III: Long-Term Resource Plan, Page 26, Tables 8 and 9.

[71] Holyrood's De-rated Adjusted Forced Outage Rate ("DAFOR"), a measure of Holyrood unavailability, for the period April 1, 2021 to March 31, 2022 was 33.84%. For the period April 1, 2022 to March 31, 2023 Holyrood DAFOR improved to 12.67%. Hydro's near-term planning assumption for Holyrood is a DAFOR of 14.00%. See Hydro's *Quarterly Report on Performance of Generating Units – For the Twelve Months Ended March 31, 2023*, dated April 28, 2023. Further to this, Hydro's *2023-2024 Winter Readiness Planning Report* was filed with the Board on October 13, 2023. It indicates that the 170 MW Holyrood Unit 2 is expected to be unavailable for the majority of the upcoming winter season. It is tentatively scheduled to be returned to service in mid-March 2024.

[72] See Hydro's 2022 Update, Page 3, Lines 22-25 and Volume III: Long-Term Resource Plan, Attachment 6, Bay d'Espoir Hydro Generating Unit 8, Summary Report, page i.

[73] See Hydro's July 14, 2023 letter *Re: Reliability and Resource Adequacy Study Review – Issues and Additional Studies Proposed by the Parties – Hydro's Comments,* page 4.

[74] Hydro filed its *Reliability and Resource Adequacy Study Review – Listing of Reports, Studies, and Analyses* report with the Board on May 25, 2023. The report outlined 17 separate studies including: (i) four separate investigation reports related to LIL equipment failure; and (ii) 13 studies related to supply options and support. The studies are scheduled to be complete between August 2023 and the fourth quarter of 2024.

[75] See Hydro's July 14, 2023 letter *Re: Reliability and Resource Adequacy Study Review – Issues and Additional Studies Proposed by the Parties – Hydro's Comments*, page 6.

The findings and recommendations associated with Hydro's 2022 Update are a departure from previous iterations of the Reliability and Resource Adequacy Study. The lower anticipated reliability of the LIL increases the likelihood of customer outages and necessitates the continued use of Holyrood and Hardwoods until alternative sources of generation are approved, constructed and commissioned. Costs associated with additional sources of capacity and the continued use of Holyrood and Hardwoods are incremental to the Muskrat Falls Project costs and expected to put additional pressure on customer electricity rates.[76]

Integration of the Muskrat Falls Project will impact the cost and reliability of supply for Newfoundland Power's customers. This integration combined with: (i) the continued use of Holyrood and Hardwoods; (ii) additional sources of capacity, such as Bay d'Espoir Unit 8; and (iii) refurbishment of Hydro's existing supply assets, can put pressure on Newfoundland Power's ability to earn a fair return.[77]

Cost Flexibility

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

[76] In the response to Request for Information PUB-NLH-236 filed in relation to Hydro's 2022 Update, Hydro provided a high-level estimate of what the potential rate impact could be based on an estimate of the cost of generation builds over the ten-year forecast period. The estimate includes customer rates increasing from 13.63 ¢/kWh in 2023 to 16.55 ¢/kWh in 2026, 18.20 ¢/kWh in 2029 and 19.34 ¢/kWh in 2032.

[77] In Order No. P.U. 6 (2023), the Board approved refurbishment of Bay d'Espoir Penstock 1 at an estimated cost of $51 million over the 2023 through 2025 period. Hydro is continuing to assess the timing of work on Penstocks 2 and 3 and will include the projects in the appropriate capital budget applications. See the response to Request for Information NP-NLH-012 (b) filed in relation to Hydro's *Application for Approval of Capital Expenditures for Section Replacement and Weld Refurbishment for Bay d'Espoir Hydroelectric Generating Facility Penstock 1*.

Table 3-13 provides revenue and costs for Newfoundland Power on a cents per kWh basis for 2002, 2012 and 2022.

Table 3-13:
Revenue and Costs
2002, 2012, 2022
(¢ per kWh)

	2002	**2012**	**2022**	**Change (2002-2022)**
Revenue	7.76	10.31	12.6	+62%
Purchased Power Costs[78]	4.42	6.73	8.29	+88%
Fixed Costs[79]	1.74	1.99	2.29	+32%
Operating Costs	0.98	0.96	1.19	+21%

Purchased power costs increased by approximately 88% on a cents per kWh basis from 2002 to 2022. Fixed costs increased by approximately 32% over the same period. Combined, these costs made up approximately 84% of revenues on a cents per kWh basis in 2022. 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 two decades. On a cents per kWh basis, operating costs increased by 21% over the period 2002 to 2022. When adjusted for inflation, operating costs decreased by approximately 26% on a cents per kWh basis over this period.[80] This is reflective of sound cost management.

78 In 2002, purchased power costs totaled approximately $211 million. In 2022, these costs increased to approximately $480 million.
79 Fixed costs include depreciation, employee future benefits, finance charges and income taxes.
80 Newfoundland Power's operating costs were approximately 1.60 cents per kWh in 2002 when adjusted for inflation. (1.19 – 1.60) / 1.60 = -0.26, or -26%.

Operating costs comprise a smaller proportion of total revenue on a cents per kWh basis in 2022 compared to 2002.[81] The reduction of operating costs as a proportion of revenue reduces the Company's flexibility to respond to changes in the business, including variances in electricity 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 issues long-term first mortgage bonds in series of $100 million or less. These bond issues are typically purchased by a small number of investors. Over the past 10 years, issuances were purchased by an average of five investors.[82] The general capital market requirement for inclusion in widely traded bond indices is $100 million and a minimum of 10 investors. Issuances, such as Newfoundland Power's, that are typically 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.[83] 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.[84] Newfoundland Power's small size relative to its peers continues to define its risk profile.

[81] On a cents per kWh basis, operating costs comprised 13% of total revenue in 2002 and 9% of total revenue in 2022.
[82] In 2015, the Company issued $75 million in Series AO First Mortgage Bonds to four investors. In 2017, the Company issued $75 million in Series AP First Mortgage Bonds to four investors. In April 2020, the Company issued $100 million in Series AQ First Mortgage Bonds to five investors. In 2022, the Company issued $75 million in Series AR First Mortgage Bonds to four investors. In 2023, the Company issued $90 million in Series AS First Mortgage Bonds to seven investors. Each bond issue was privately placed.
[83] See Order No. P.U. 16 (1998-99), page 37.
[84] See Order No. P.U. 19 (2003), page 45.

Operating Environment

Newfoundland Power is primarily a distribution utility. The Company currently serves approximately 275,000 customers on the island of Newfoundland. The majority of the Company's customers are residential customers.[85] Approximately 74% of Newfoundland Power's residential customers rely on electricity as their primary heating source.[86]

The Company's electrical system includes approximately 9,500 kilometres of distribution line and 2,100 kilometres of transmission line. Most of this distribution and transmission infrastructure is overhead construction and exposed to the elements.[87]

The majority of customer outages occur on the distribution system.[88] The leading causes of outages on the distribution system are related to adverse weather conditions, including high winds.[89]

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.[90] These conditions

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[85] At June 30, 2023, the Company had 274,629 customers. Of those, 239,081 were residential (i.e. domestic) customers, 24,484 were general service customers, and 11,064 were street and area lighting customers.

[86] Of Newfoundland Power's 239,081 domestic customers, 176,657 used electricity as the primary source of household heating (176,657 / 239,081 = 0.74, or 74%).

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

[88] Based on outage duration, an average of approximately 89% of customer outages in Canada occurred on the distribution system over the period 2018 to 2022. See Electricity Canada, *2022 Distribution System Performance – Electric Power System Reliability Assessment, Service Continuity Annual Report*.

[89] Based on outage duration, approximately 60% of customer outages on the distribution system over the 2018 to 2022 period were caused by adverse weather, including trees contacting distribution lines. See Electricity Canada, *2022 Distribution System Performance – Electric Power System Reliability Assessment, Service Continuity Annual Report*.

[90] 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 four classifications of weather load conditions for ice accumulation, wind loading and temperature. These are: (i) medium loading B; (ii) medium loading A;

have resulted in large-scale customer outages.[91]

Changing climate conditions can also pose challenges to the reliability of service to Newfoundland Power's customers. The Atlantic Provinces Economic Council ("APEC") has stated that a greater occurrence of severe weather events is currently impacting the electricity industry, and presents system planning and operational challenges for utilities.[92] APEC also notes that a future risk of climate change is an increasing need to build reliable electricity systems as the climate becomes more unpredictable.[93]

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.

(iii) heavy; and (iv) severe. Newfoundland Power's service territory has *heavy* and *severe* loading classifications. Only two 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.

91 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 eight 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. In September 2021, Hurricane Larry impacted the east coast of Newfoundland bringing sustained winds of 120 km/h and gusts between 150 km/h and 175 km/h causing outages to approximately 50,000 customers.

92 See page 4 of the Atlantic Provinces Economic Council's report, *An Overview of Atlantic Canada's Coming Economic Transition*, October 2022.

93 Ibid.

This can result in unpredictability in costs.[94] Unpredictable costs can result in volatility in earnings.[95]

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.

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.[96] 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 in a timely manner. The RSA includes an Energy Supply Cost Variance Clause that addresses variances in purchased power costs resulting from variances in energy purchases requirements, and differences between the incremental rate that the Company pays and the average supply cost in customer rates.[97]

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[94] 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; (iii) in January 2020, a severe blizzard resulted in costs of approximately $1 million; and (iv) in September 2021, Hurricane Larry resulted in costs of approximately $1.6 million.

[95] 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).

[96] A report on the Company's supply cost mechanisms was filed in Newfoundland Power's *2022/2023 General Rate Application* in response to Request for Information PUB-NP-041. Supply cost recovery practices for investor-owned distribution utilities in Canada were described in Appendix A to the report.

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

Other supply cost mechanisms include: (i) a Weather Normalization Reserve that normalizes the effects of weather and hydrology on electricity sales;[98] and (ii) a DMI Account that limits the impacts of variability in demand supply costs.[99]

Employee future benefits are recovered through two regulatory mechanisms. The Pension Expense Variance Deferral Account was approved by the Board in 2009.[100] The OPEB Cost Variance Deferral Account was approved by the Board in 2010.[101] These mechanisms address annual fluctuations in pension and OPEB costs that are beyond management control.[102] Such mechanisms have been approved in other Canadian jurisdictions to address increased volatility of employee future benefits costs.[103]

Two regulatory mechanisms are designed to provide for the recovery of costs associated with customer program delivery. The Conservation and Demand Management ("CDM") Deferral Account was approved by the Board in 2009 and 2013.[104] An Electrification Cost Deferral Account was approved by the Board in 2022.[105] These mechanisms are designed to provide for the deferred recovery of costs related to the delivery of customer CDM programs, which vary annually due to variations in customer participation, as well as costs associated with electrification initiatives approved by the Board.

[98] See Order No. P.U. 13 (2013).
[99] See Order No. P.U. 32 (2007).
[100] See Order No. P.U. 43 (2009).
[101] See Order No. P.U. 31 (2010).
[102] 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.
[103] Employee future benefits cost recovery mechanisms are also in effect for utilities in Ontario, Alberta and British Columbia.
[104] See Order Nos. P.U. 13 (2009) and P.U. 13 (2013).
[105] See Order No. P.U. 3 (2022).

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.[106] 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 generally limits the Company's return on equity to approximately 40 basis points above the approved return for ratemaking purposes.[107]

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

[106] 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.
[107] Based on debt costs remaining constant from test year levels.

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 2025 and 2026 based on the Company's existing scenario and the proposals contained in this Application.

Table 3-14 provides a summary of Newfoundland Power's regulated returns under the Company's existing scenario and the proposals in this Application.

Table 3-14:
Comparative Rates of Return
Existing and Proposed
2025 and 2026

	2025E	2025P	2026E	2026P
Return on Rate Base (%)	6.24	7.40	5.84	7.21
Return on Equity (%)	7.16	9.85	6.38	9.85

Newfoundland Power's rates of return on rate base for 2025 and 2026, excluding the proposals in this Application, are 6.24% and 5.84%, respectively. This equates to returns on equity of 7.16% for 2025 and 6.38% for 2026.

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 9.85% based upon a capital structure with a 45% common equity component.[108]

[108] See *Volume 2, Supporting Materials, Tab B, Cost of Capital.*

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

Table 3-15:
Credit Metrics
Existing and Proposed
2025 and 2026

	2025E	2025P	2026E	2026P
Pre-tax Interest Coverage (times)	2.2	2.8	2.0	2.8
Cash Flow Interest Coverage (times)[109]	2.9	3.4	2.8	3.7
Cash Flow Debt Coverage (%)[110]	9.6	13.2	9.0	14.1

Maintaining Newfoundland Power's existing scenario results in deteriorating credit metrics for 2025 and 2026. With the proposals in this Application, the credit metrics will allow Newfoundland Power to issue first mortgage bonds in 2025 and 2026, and will more closely reflect the stable and consistent financial strength observed by Moody's[111] and DBRS.[112]

[109] Excluding the impact of energy supply cost variances, Newfoundland Power's cash flow interest coverage under proposed rates would be 4.4 times in 2025 and 4.6 in 2026. See *Section 3.2.8: Credit Metrics* and *Section 4.3.4: Deductions from Revenue Requirement.*

[110] Excluding the impact of energy supply cost variances, the Company's cash flow debt coverage under proposed rates would be 18.4% in both 2025 and 2026. See *Section 3.2.8: Credit Metrics* and *Section 4.3.4: Deductions from Revenue Requirement.*

[111] In its March 31, 2023 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).

[112] In its October 13, 2023 Rating Report, filed in Exhibit 4 to this Application, DBRS states: *"Newfoundland Power has maintained a solid financial profile, underpinned by its reasonable financial leverage and stable cash flow. For the last 12 months ended June 30, 2023 (LTM 2023), Newfoundland Power's key credit metrics were in line with the current credit rating range, with total debt in the capital structure at 57.4%, the cash flow-to-debt ratio at 17.5%, and EBIT interest coverage at 2.61x"* (page 2 of 14).

The Company's cash flow metrics since 2020 have fluctuated, largely due to the operation of the Energy Supply Cost Variance Clause and the current wholesale rate structure.[113] This cash flow volatility is expected to decrease following Hydro's next GRA, which is expected to include a revised wholesale rate for Newfoundland Power reflecting commissioning of the Muskrat Falls Project.[114]

3.3.4 Automatic Adjustment Formula

The Board adopted the Formula in 1998 to determine changes to the Company's return on equity between rate applications.[115] 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.

The Board suspended use of the Formula in December 2011 following an Application by Newfoundland Power.[116] Operation of the Formula at the time would have resulted in a return on rate base for Newfoundland Power that would have reflected a regulated return on equity of 7.85%.[117]

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[113] For example, in 2021, the Energy Supply Cost Variance Clause resulted in positive cash flows of approximately $25.4 million, while cash flows for 2023 are forecast to be negatively impacted by approximately $32.3 million. This cash flow variance totals $57.7 million.

[114] For more information, see *Section 3.2.8: Credit Metrics*. In its September 2023 update, Hydro provided that it expects the earliest timeframe for its next general rate application to be the latter half of 2024.

[115] 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 ("AUC"), the Ontario Energy Board ("OEB"), 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).

[116] See Order No. P.U. 25 (2011).

[117] The Consumer Advocate filed submissions and evidence in response to Newfoundland Power's Application, including a report from cost of capital expert, Dr. Lawrence Booth, and advised the Board that the Consumer Advocate would not take issue with the suspension of the Formula.

The use of the Formula was suspended in subsequent Board orders including the Board's order in relation to Newfoundland Power's *2013/2014 General Rate Application*. 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."*[118]

In Order Nos. P.U. 18 (2016), P.U. 2 (2019), and P.U. 3 (2022), the Board accepted settlement agreements in relation to the Formula and was satisfied, based on the evidence, that continued suspension of the Formula remained appropriate.[119] This is consistent with current Canadian regulatory practice.[120]

Since Newfoundland Power's *2022/2023 General Rate Application* bond yields have increased. However, financial market conditions have been volatile. One measure of financial market volatility is short-term debt yields compared to long-term debt yields. In normal economic conditions, short-term government bond yields are lower than long-term government bond yields. In more volatile economic conditions, the opposite it true. This is referred to as an inverted yield curve.[121]

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[118] See Order No. P.U. 13 (2013), page 36, lines 38-44.

[119] See Order No. P.U. 18 (2016), page 10, lines 15-26, Order No. P.U. 2 (2019), page 15, lines 13-24, and Order No. P.U. 3 (2022), page 17, lines 17-33.

[120] Only the OEB and AUC use a ROE adjustment formula. See *Volume 2, Supporting Materials, Tab B, Cost of Capital, Section VII. Automatic Adjustment Formula*. In 2009, the OEB concluded that a formulaic 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). In Alberta, the formulaic approach will apply to 12 electric and gas utilities regulated by the AUC (see page 1 of AUC Decision 27084-D02-2023).

[121] See World Economic Forum, *What does an inverted yield curve look like and what does it signal about an economy?*, December 19, 2022.

Figure 3-5 shows two-year Government of Canada benchmark bond yields in comparison to long-term Government of Canada benchmark bond yields for the period January 2001 to July 2023.

Figure 3-5:
Government of Canada
Benchmark Bond Yields[122]
(2001 – 2023)

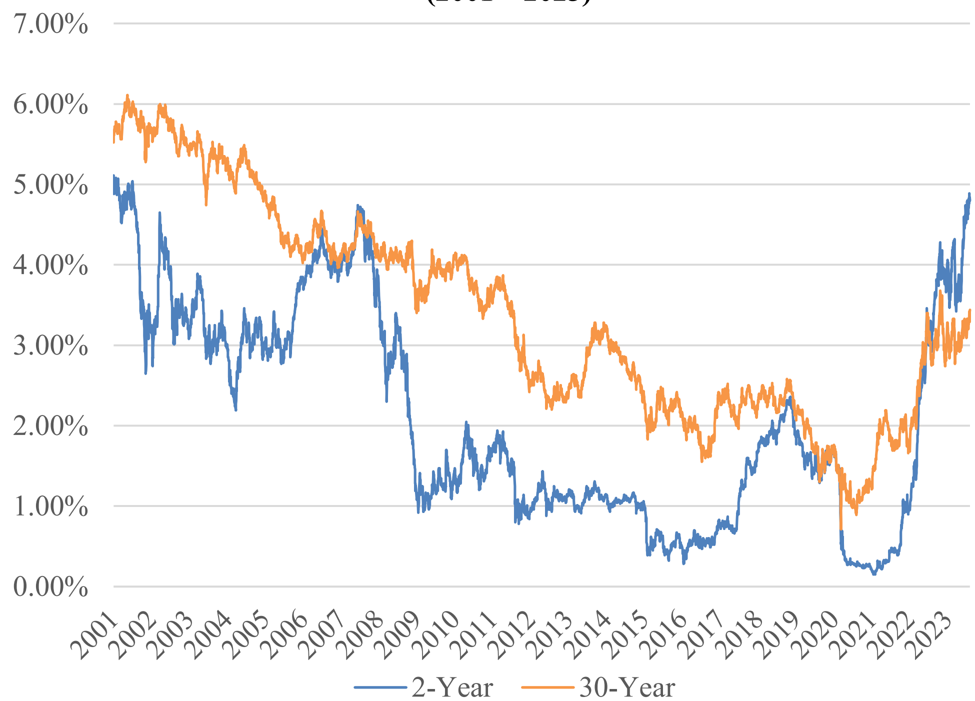

Figure 3-5 shows three periods where yields on two-year Government of Canada benchmark bonds were comparable to, or higher than, long-term Government of Canada benchmark bond yields. These include: (i) the 2007-2008 period defined by the global financial crisis;[123] (ii) the

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122 Source: Bank of Canada – Selected bond yields https://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/.

123 See Federal Reserve History, *The Great Recession and its Aftermath*, November 22, 2013, which states, "*In 2007, losses on mortgage-related financial assets began to cause strains in global financial markets, and in December 2007 the U.S. economy entered a recession... In the fall of 2008, the economic contraction worsened, ultimately becoming deep enough and protracted enough to acquire the label "the Great Recession.*"

2019-2020 period defined by the onset of the COVID-19 pandemic;[124] and (iii) the 2022-2023 period defined by high inflation and increases in the central bank target overnight interest rate.[125]

In Newfoundland Power's view, current economic conditions do not provide the stability in financial markets necessary to establish a formula that can be used to adjust the Company's return on equity between test years. The result of a formula used to adjust Newfoundland Power's return on equity would require the Board to exercise further judgment. The expert evidence filed with this Application also recommends continued suspension of the Formula.[126]

For these reasons, the Application proposes continued suspension of the Automatic Adjustment Formula for determining Newfoundland Power's rate of return on equity between test years.

3.4 REGULATORY ACCOUNTING MATTERS

The Application proposes changes to the Rate Stabilization Clause to allow for recovery of deferred electrification costs over 10 years, commencing January 1, 2025. Consistent with the recovery of CDM costs, the amortization amount will be charged to Newfoundland Power's Rate Stabilization Account annually on March 31st to be included in the annual July 1st rate adjustment.

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[124] During the COVID-19 pandemic, Canada's GDP contracted by 5.2% and the unemployment rate reached 13.4%. See Fraser Institute, *Storm Without End – The Economic and Fiscal Impact of COVID in Canada*, 2022.

[125] Inflation in Canada reached 8.1% in summer of 2022. In an effort to reduce inflation to its 2% target, the Bank of Canada increased its target overnight interest rate 10 times from 0.25% in March 2022 to 5.0% by July 2023. See CBC News, *Bank of Canada raises its key interest rate to 5%*, July 12, 2023.

[126] See, for example, *Volume 2, Supporting Materials, Tab B, Cost of Capital, Automatic Adjustment Formula*, pages 84 and 85.

The Company proposes a change to the DMI Account definition to establish a threshold of ± $500,000. The proposed threshold will continue to provide an incentive to Newfoundland Power to minimize peak demand while recognizing the Company's limitations in managing its demand costs. A threshold of ± $500,000 is consistent with prior approvals of the Board.

3.4.1 Amortization of Deferred Electrification Costs

Background

In Order No. P.U. 3 (2022), the Board approved the establishment of the Electrification Cost Deferral Account.[127] However, the Board did not approve the Company's proposed amendments to Clause II.9 of the RSA to allow for the recovery of costs in the Electrification Cost Deferral Account over a 10-year period through its RSA. The Board provided that the proposal should be considered as part of the *2021 Electrification, Conservation and Demand Management Application*.[128]

In Order No. P.U. 33 (2022) associated with the *2021 Electrification, Conservation and Demand Management Application*, the Board agreed with the 10-year recovery period for deferred electrification costs, stating:

> *"The Board agrees with Newfoundland Power that a ten-year period to recover costs associated with electrification initiatives is also appropriate and consistent with sound utility practice, current practices for CDM initiatives and regulatory fairness principles."*[129]

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[127] See Order No. P.U. 3 (2022), page 21, line 30.
[128] See Order No. P.U. 3 (2022), page 11, lines 3-6.
[129] See Order No. P.U. 33 (2022), page 18, lines 11-14.

However, the Board did not approve the Company's proposed amendments to Clause II.9 of the RSA in Order No. P.U. 33 (2022). The Board provided that Newfoundland Power may file for the necessary approvals with respect to the recovery of approved electrification costs.[130]

Amortization of the Electrification Deferral Account

Newfoundland Power proposes to recover approved customer electrification costs through its RSA over 10 years, commencing January 1, 2025.

Table 3-16 provides the forecast deferral and amortization amounts associated with approved customer electrification initiatives from 2022 to 2026P.

Table 3-16:
Electrification Costs
Forecast Deferrals and Amortizations
2022 to 2026P
($000s)

	2022	**2023F**	**2024F**	**2025P**	**2026P**
Charges to Deferral Account[131]	(1,598)	(762)	(733)	(743)	(776)
Forecast Amortization[132]	-	-	-	309	384

Consistent with the recovery of CDM costs, the amortization amount will be charged to Newfoundland Power's RSA annually on March 31st to be included in the annual July 1st rate adjustment.

130 See Order No. P.U. 33 (2022), page 18, lines 19-21.

131 Charges to this account include: (i) capital and operating costs associated with the Electric Vehicle ("EV") charging infrastructure approved in Order No. P.U. 30 (2021); (ii) costs associated with the EV Demand Management Pilot approved by the Board in Order No. P.U. 23 (2023); and (iii) interest charges. These charges are partially offset by revenues related to charging infrastructure, which include charging revenues, and government funding.

132 Amortizations are charged to Newfoundland Power's RSA on March 31st in each year.

Exhibit 13 in *Volume 1, Application, Company Evidence and Exhibits* provides the proposed revisions to the Rate Stabilization Clause to reflect the amortization of deferred electrification costs over 10 years.

3.4.2 Demand Management Incentive

Background

In its *2008 General Rate Application*, the Company proposed the establishment of a DMI Account to replace the Purchased Power Unit Cost Variance Reserve Account. It was intended to provide an incentive for Newfoundland Power to undertake reasonable initiatives to minimize peak demand and to provide the ability for the Company to recover costs associated with variability in purchased power costs inherent in the demand and energy wholesale rate.[133]

The DMI Account is charged or credited with the amount that the demand supply cost variance exceeds the DMI, calculated as ± 1% of test year wholesale demand charges. Newfoundland Power files an annual application with the Board to address the disposition of any balance in the DMI Account. Any required recovery from, or credit to, customers arising from a DMI balance is included in the Company's annual RSA adjustment.

[133] In Order No. P.U. 44 (2004), the Board approved the demand and energy rate to Newfoundland Power as proposed by Hydro to be effective January 1, 2005 along with a three-year phase-in plan. In Order No. P.U. 32 (2007), the Board approved the definition of the DMI Account to be included in Newfoundland Power's System of Accounts. In Order No. P.U. 43 (2009), the Board approved the continued use of the DMI Account.

Managing Demand Costs and Changes since 2008

Newfoundland Power has limited ability to manage system demand on a peak day.[134] Peak demand is typically driven by a period of extremely cold weather and normally occurs in the morning or early evening. Peak demand varies annually depending on timing and weather conditions.[135]

When the DMI Account was first established, the Company had two practical ways to manage system demand on a peak day: voltage management[136] and customer curtailment.[137] In addition, customer energy efficiency programs were gaining momentum, which provided an opportunity to implement programs to lower system demand.

Since the establishment of the DMI Account, Newfoundland Power's ability to reduce its purchased power demand costs from those reflected in customer rates has become more limited.

The Company forecasts its peak demand, which is based on a historical average load factor, to estimate its expected purchased power costs from Hydro throughout the test year period used to set customer rates.[138] As Newfoundland Power has implemented voltage management in past

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[134] The native peak is the maximum amount of customer energy usage required during any 15-minute time period during the year. The billing demand is computed from the annual native peak less the credit for Newfoundland Power's generation and curtailment. The billing demand cannot be less than the minimum billing demand that is set at 99% of test year billing demand.

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

[136] Newfoundland Power exercises its voltage reduction capabilities to be within the voltage variation limits of CSA Standards to ensure acceptable voltage levels are maintained with customers.

[137] There are currently 24 customers on Newfoundland Power's Curtailable Service Option which provide for approximately 12 MW of demand reduction. For more information on the Company's Curtailable Service Option, see the *2023 Curtailable Service Option Report* filed with the Board on April 28, 2023.

[138] For further information on Newfoundland Power's peak demand forecast, see *Volume 2, Supporting Materials, Tab 3, Customer, Energy and Demand Forecast*.

years to lower peak demand, that demand reduction is embedded into the forecast used to set customer rates. As a result, the Company is now effectively required, rather than incentivized, to employ voltage management to maintain its purchased power demand costs.

In Order No. P.U. 49 (2016), the Board determined that curtailment should only be requested from Newfoundland Power's customers where there is a *bona fide* system constraint. Previously, customer curtailment was also used by the Company to reduce demand requirements during peak load conditions. As such, the Company no longer has the ability to employ customer curtailment to lower its demand costs from the level determined in a test year.[139]

Newfoundland Power and Hydro have been implementing customer CDM programs under the takeCHARGE partnership since 2009. Customer programming has matured over that time frame.[140] Five-year plans are considered by the Board as part of Newfoundland Power general rate applications and separate proceedings, as required. Forecast results, including lower energy and demand savings, are reflected in test year purchased power costs. Therefore, there is limited ability for the Company to exceed the results set out in the plans.

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139 Test year billing demand includes the curtailment credit. In accordance with the Utility rate charged by Hydro, if curtailment is requested on the peak day that ultimately determines Newfoundland Power's billing demand for that year, there is no curtailment credit. In this scenario, similar to the voltage management discussion above, the Company must employ customer curtailment to maintain its purchased power demand costs determined in a test year.

140 The current five-year plan (2021 to 2025) is the fourth consecutive plan implemented by the utilities.

Newfoundland Power is subject to the wholesale rate charged by Hydro. While the Company consults with Hydro on the design of the wholesale rate, it is not within Newfoundland Power's control.[141]

Since 2008 the demand rate has increased by over 40%,[142] and there is risk that the demand rate could increase further as part of Hydro's next general rate application.[143] In addition, the wholesale rate includes a Minimum Billing Demand which can limit the Company's ability to control its demand costs.[144] For example, Newfoundland Power's peak demand for the 2019-2020 winter season was 1,367.3 MW, which equates to a billing demand of 1,238.3 MW. However, as this amount was less than Hydro's minimum billing demand of 1,251.1 MW, the Company's demand costs for 2020 were determined using the minimum billing demand of 1,251.1 MW, eliminating the ability for Newfoundland Power to manage its demand costs in that year.

Industry Practice

Mechanisms that permit full recovery of energy supply costs by investor-owned distribution utilities are common in Canadian regulatory practice.[145] The widespread use of supply cost

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[141] The Utility rate is commonly referred to as the wholesale rate.

[142] In 2008, the demand rate was $4.00 per kW, which resulted in a DMI threshold of just over $500,000. In 2023, the demand rate is $5.00 per kW, which provides for a DMI threshold of approximately $750,000. Over the 15-year period, the DMI threshold has increased $750,631 ÷ 528,907 – 1 = 42%.

[143] For example, Hydro's *Marginal Cost Projections 2023-2040 for the Island Interconnected System* dated December 2022 provides a Generation and Transmission capacity cost for 2023 of $307.14 per kW per year.

[144] The Utility rate includes a Minimum Billing Demand component, which ensures Hydro has the ability to collect 99% of its test year demand costs.

[145] A report on the Company's supply cost mechanisms was filed in Newfoundland Power's *2022/2023 General Rate Application* in response to Request for Information PUB-NP-041. Supply cost recovery practices for investor-owned distribution utilities in Canada were described in Appendix A to the report. Such regulatory mechanisms also appear to be common in the U.S. See *Volume 2, Supporting Materials, Tab B, Cost of Capital, Comparison to U.S. Electric Utility Proxy Group*.

mechanisms reflects that the cost of supply is typically the largest single cost for a distribution utility.[146]

Incentive thresholds are less common. Other than Newfoundland Power, Nova Scotia Power is the only Canadian investor-owned utility that has a threshold associated with its supply cost mechanism.[147]

In addition to the threshold on Newfoundland Power's demand costs, the Board has approved thresholds associated with Hydro's supply costs.[148] With respect to the implementation of the threshold associated with Hydro's Holyrood Conversion Rate Deferral Account, the Board provided that the use of the threshold reflected the fact that some aspects of the Holyrood conversion rate are within Hydro's control.[149]

Proposed Change in Threshold of the DMI Account

Newfoundland Power proposes to revise the DMI Account definition to replace the calculation of the threshold from ± 1% of test year wholesale demand charges to ± $500,000 with effect from January 1, 2025.

[146] Purchased power expense is Newfoundland Power's largest cost, accounting for approximately two-thirds of revenue from rates in 2023.

[147] See, for example, *Volume 2, Supporting Materials, Tab B, Cost of Capital, Comparison to other Canadian Investor-Owned Electric Utilities, Power Supply Risk*. Under its Fuel Adjustment Mechanism, Nova Scotia Power has an incentive threshold for fuel cost variances whereby 90% of any savings or increase in fuel costs are credited or charged to customers, up to $50 million.

[148] In Order No. P.U. 49 (2016), the Board approved a ± $500,000 cost threshold associated with Hydro's Holyrood Conversion Rate Deferral Account, Energy Supply Cost Variance Deferral Account and Isolated Systems Supply Cost Variance Deferral Account. Upon discontinuance of Hydro's Rate Stabilization Plan and approval of Hydro's Supply Cost Variance Deferral Account ("SCVDA") approved in Order No. P.U. 4 (2022), the Board maintained two ± $500,000 cost thresholds associated with Hydro's supply costs. Both Hydro's Isolated Systems Supply Cost Variance Deferral Account and the Other Island Interconnected System Supply Cost Variance component of the SCVDA include a ± $500,000 cost threshold.

[149] See Order No. P.U. 49 (2016), page 122.

Since 2008, Newfoundland Power's ability to reduce its purchased power demand costs has become more limited, while the cost threshold has increased by more than 40% and there is risk of further increase.

While the use of thresholds associated with supply cost mechanisms is not the prevalent practice in Canada, the Board has approved cost thresholds of ± \$500,000 associated with certain Hydro supply costs.[150]

In Newfoundland Power's view, a ± \$500,000 threshold would reflect that, while limited, there are some aspects to managing peak day demand that are within the Company's control. The proposed threshold level is consistent with prior orders of the Board. The defined amount continues to provide an incentive for Newfoundland Power to reduce system demand and appropriately limits risks associated with recovery of demand costs due to factors outside of Newfoundland Power's control, such as increasing cost components of the wholesale rate.

Exhibit 14 in *Volume 1, Application, Company Evidence and Exhibits* provides the proposed revisions to the DMI Account definition to reflect the changes to the calculation of the demand cost threshold.

[150] The ± \$500,000 amount is also consistent with the cost threshold level associated with Newfoundland Power's DMI Account when it was first established by the Board in Order No. P.U. 32 (2007).

3.5 REGULATORY AMORTIZATIONS

3.5.1 Overview

Table 3-17 summarizes the amortization of regulatory deferrals approved by the Board and the amortization of regulatory deferrals proposed in this Application.

Table 3-17:
Amortization of Regulatory Deferrals
***Pro forma* Revenue Requirement Impact**
2022 to 2026P
($000s)

	2022	**2023F**	**2024P**	**2025P**	**2026P**
2022 Revenue Shortfall[151]	(656)	328	328	-	-
Pension Capitalization Deferral[152]	-	(1,144)	(568)	492	492
Hearing Costs Deferral[153]	-	-	-	200	400
2024 Revenue Shortfall[154]	-	-	(6,722)	1,344	2,689
2025 Revenue Shortfall[155]	-	-	-	(13,407)	6,707
Revenue Requirement Impact	**(656)**	**(816)**	**(6,962)**	**(11,371)**	**10,288**

3.5.2 Pension Capitalization Cost Deferral Account

In Order No. P.U. 3 (2022), the Board approved revisions to the Company's general expenses capitalized calculation effective January 1, 2023, which included the use of a deferral account to

[151] In Order No. P.U. 3 (2022), the Board approved the amortization of a revenue shortfall of $930,000 related to the March 1, 2022 rate implementation date over a 34-month period commencing on March 1, 2022 and ending December 31, 2024. This represents approximately $27,000 per month. For 2022, it represents amortization over a 10-month period, or approximately $274,000 ($930,000 - $274,000 = $656,000). For 2023 and 2024, this represents approximately $328,000 per year.

[152] In 2023 and 2024, $1.4 million and $1.1 million, respectively, is forecast to be charged to the Pension Capitalization Cost Deferral Account and amortized over a five-year period. For 2025 and 2026, this results in amortization cost of approximately $492,000 each year. See *Section 3.5.2: Pension Capitalization Cost Deferral Account.*

[153] The amortization of $1.0 million related to Newfoundland Power's *2025/2026 General Rate Application* hearing costs is proposed in this Application. See *Section 3.5.3: Hearing Costs.*

[154] See *Section 3.5.4: 2024 Revenue Shortfall.*

[155] See *Section 3.5.5: 2025 Revenue Shortfall.*

offset the income tax impact of the change in capitalizing pension costs, with amortization of the amounts over a five-year period commencing January 1, 2023. Newfoundland Power proposes to amend the Pension Capitalization Deferral Account to cease charges to the account effective December 31, 2024. Prior charges to the account will continue to be amortized over five years.

Exhibit 15 in *Volume 1, Application, Company Evidence and Exhibits* provides the proposed revisions to the Pension Capitalization Cost Deferral Account definition.

3.5.3 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 *2025/2026 General Rate Application*. Consistent with previous Board practice, Newfoundland Power proposes to recover these costs in customer rates over a 30-month period commencing on July 1, 2025 and ending December 31, 2027.[156] 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.[157]

[156] In the past, the Board has ordered recovery of Application costs over a three-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). In the settlement agreement for the *2022/2023 General Rate Application*, the Board approved the recovery of hearing costs directly through the RSA in 2022.

[157] Recovery of $1.0 million in estimated 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 the actual and estimated costs to be rebated or collected through the RSA. The settlement agreement was approved in Order No. P.U. 2 (2019).

3.5.4 2024 Revenue Shortfall

In Newfoundland Power's *2024 Rate of Return on Rate Base Application*, the Company proposed deferred cost recovery of a 2024 Revenue Shortfall amount of $6,722,000.[158] Newfoundland Power proposes to amortize this amount over a 30-month period commencing on July 1, 2025 and ending December 31, 2027.[159]

3.5.5 2025 Revenue Shortfall

Implementation of customer rates beginning on July 1, 2025 based on the proposed 2026 revenue requirement would result in a $16,761,000 shortfall in recovering the proposed 2025 revenue requirement. Consistent with the 2024 revenue shortfall, the Company proposes to amortize this amount over a 30-month period commencing on July 1, 2025 and ending December 31, 2027.[160]

The proposed treatment of both the 2024 and 2025 revenue shortfall amounts are consistent with past practice of the Board.[161]

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[158] For further information, see Section 6.3 2024 Revenue Shortfall in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

[159] This represents amortization of approximately $224,000 per month. For 2025, it represents amortization over a six-month period, or approximately $1,344,000. For 2026 and 2027, this represents approximately $2,689,000 per year.

[160] This represents an amortization of approximately $559,000 per month. For 2025, it represents amortization over a six-month period, or approximately $3,354,000 ($16,761,000 - $3,354,000 = $13,407,000). For 2026 and 2027, this represents approximately $6,707,000 per year.

[161] In Order No. P.U. 13 (2013), the Board approved recovery of a forecast revenue shortfall 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 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. In Order No. P.U. 3 (2022), the Board approved final customer rates resulting from the Company's *2022/2023 General Rate Application*. This included the amortization of a revenue shortfall for 2022 resulting from the March 1, 2022 implementation.

3.5.6 Load Research and Rate Design Cost Deferral Account

As part of the settlement agreement associated with Newfoundland Power's *2023/2023 General Rate Application*, the parties agreed that the Company conduct a Load Research Study and a Retail Rate Design Review (collectively, the "Studies"). In Order No. P.U. 3 (2022), the Board approved Newfoundland Power's Load Research and Rate Design Cost Deferral Account to recover the costs incurred to conduct the Studies.

In 2022, the Company provided a detailed framework associated with the Studies.[162] In 2023, with consultation from the parties, Newfoundland Power prepared plans and scopes of work associated with the Studies and engaged consultants to commence the necessary work.

As outlined in the framework for the Studies, work activities associated with the Load Research Study are expected to occur over the 2023 to 2025 period, and could extend into 2026.[163] Work activities associated with the Retail Rate Design Review are expected to occur over the 2023 and 2024 period, however, may be extended depending on the timing of the implementation of post-Muskrat Falls wholesale revenue requirements and rate designs.[164]

The account definition provides that the disposition of any balance in this account will be subject to a future order of the Board. In Newfoundland Power's view, determining the disposition of the account as part of the Company's next general rate application would be reasonable.

[162] See Newfoundland Power's *Load Research and Rate Design Framework* filed with the Board on December 30, 2022.
[163] Ibid., pages 4 and 5.
[164] Ibid., page 8.

SECTION 4: RATE BASE AND REVENUE REQUIREMENT

4.1 OVERVIEW

This section of evidence addresses the Company's forecast 2025 and 2026 average rate base and revenue requirements.

Based on the Application, forecast 2025 and 2026 average rate base is approximately $1,407 million and $1,451 million, respectively.

Based on the Application, the forecast 2025 and 2026 revenue requirements are approximately $769 million and $790 million, respectively.

To generate the revenue necessary to meet the Company's forecast revenue requirements in 2025 and 2026, an average increase in customer rates of approximately 5.5% will be required effective July 1, 2025.

4.2 2025 AND 2026 RATE BASE

Exhibit 6 in *Volume 1, Application, Company Evidence and Exhibits*, provides Newfoundland Power's forecast 2025 and 2026 average rate base.

Newfoundland Power's forecast 2025 and 2026 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, Application, Supporting Materials, Tab 2, 2025 and 2026 Rate Base Allowances.*

The Company's forecast 2025 and 2026 average rate base is approximately $1,407 million and $1,451 million, respectively.

Changes to Newfoundland Power's average rate base are principally the result of: (i) plant investment, which includes annual capital expenditures;[2] and (ii) depreciation expense.[3] Forecast 2025 and 2026 average rate base include the Company's forecast capital expenditure and is calculated in accordance with established practice and Board orders.[4]

4.3 2025 AND 2026 REVENUE REQUIREMENTS

4.3.1 Summary of Revenue Requirements

Exhibit 7 in *Volume 1, Application, Company Evidence and Exhibits*, provides Newfoundland Power's 2025 and 2026 forecast revenue requirements.

The Company's revenue requirement is forecast to be approximately $769 million in 2025 and $790 million in 2026.

[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 *2024 Capital Budget Application* filed on June 22, 2023.

[3] Annual depreciation expense is currently calculated using the composite depreciation rates based on the *2019 Depreciation Study*, approved by the Board in Order No. P.U. 3 (2022).

[4] The forecast capital expenditures for 2025 and 2026 are described in the *2024 Capital Budget Application*.

Table 4-1 provides a summary of Newfoundland Power's forecast 2025 and 2026 revenue requirements and the revenue required to be recovered from customer rates.

Table 4-1:
Summary of Revenue Requirements
2025F and 2026F
($000s)

	2025F	**2026F**
Power Supply Cost	530,628	522,388
Operating Costs[5]	81,903	84,940
Employee Future Benefit Costs	8,122	1,812
Deferred Cost Recoveries and Amortizations	(11,571)	9,888
Depreciation	83,143	86,691
Income Taxes[5]	27,466	27,541
Return on Rate Base	104,049	104,667
Revenue Requirement	**823,740**	**837,927**
Adjustments		
Other Revenue	(9,223)	(6,860)
Interest on Security Deposits	72	72
Energy Supply Cost Variance Adjustments	(40,165)	(35,495)
CDM Program and Electrification Costs Amortization	(5,654)	(6,042)
Revenue Requirement from Rates	**768,770**	**789,602**

[5] 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 2025 and 2026 power supply costs.

Table 4-2:
Power Supply Costs
2025F and 2026F
($000s)

	2025F	**2026F**
Existing	533,716	531,779
Elasticity Impact	(3,088)	(9,391)
Proposed	**530,628**	**522,388**

Table 4-3 provides forecast 2025 and 2026 operating costs.[6]

Table 4-3:
Operating Costs
2025F and 2026F
($000s)

	2025F	**2026F**
Existing	81,394[7]	84,156[8]
Hearing Costs[9]	200	400
Electrification Costs Amortization[10]	309	384
Proposed	**81,903**	**84,940**

[6] Exhibits 1 and 2 in *Volume 1, Application, Company Evidence and Exhibits*, provide the forecast gross operating costs for 2025 and 2026. These are reviewed in detail in *Volume 1, Application, Company Evidence and Exhibits, Section 2.5: Operating and Capital Costs.*

[7] Existing operating costs in 2025 include: (i) gross operating costs of approximately $79.1 million (see Exhibits 1 and 2); (ii) plus amortization of CDM costs of $5.3 million, as approved by the Board in Order No. P.U. 3 (2022); (iii) less GEC of approximately $3.0 million.

[8] Existing operating costs in 2026 include: (i) gross operating costs of approximately $81.6 million (see Exhibits 1 and 2); (ii) plus amortization of CDM costs of $5.7 million as approved by the Board in Order No. P.U. 3 (2022); (iii) less GEC of approximately $3.1 million.

[9] See *Volume 1, Application, Company Evidence and Exhibits, Section 3.5.3: Hearing Costs*.

[10] See *Volume 1, Application, Company Evidence and Exhibits, Section 3.4.1: Amortization of Deferred Electrification Costs*.

1 Table 4-4 provides forecast 2025 and 2026 employee future benefits costs.

Table 4-4:
Employee Future Benefits Costs
2025F and 2026F
($000s)

	2025F	**2026F**
Pension Expense[11]	1,098	(1,824)
OPEB Expense[12]	7,024	3,636
Existing	**8,122**	**1,812**
Changes	-	-
Proposed	**8,122**	**1,812**

2 Table 4-5 provides forecast 2025 and 2026 deferred cost recoveries and amortizations.

Table 4-5:
Deferred Cost Recoveries and Amortizations
2025F and 2026F
($000s)

	2025F	**2026F**
Existing	492	492
2024 Revenue Shortfall[13]	1,344	2,689
2025 Revenue Shortfall[14]	(13,407)	6,707
Proposed	**(11,571)**	**9,888**

[11] See *Volume 1, Application, Company Evidence and Exhibits, Section 3.2.4: Employee Future Benefits, Pensions*.

[12] See *Volume 1, Application, Company Evidence and Exhibits, Section 3.2.4: Employee Future Benefits, OPEB*.

[13] The 2024 revenue shortfall of approximately $6.7 million related to the July 1, 2024 rate implementation date is proposed to be amortized evenly over a 30-month period from July 1, 2025 to December 31, 2027. See *Volume 1, Application, Company Evidence and Exhibits, Section 3.5.4: 2024 Revenue Shortfall.*

[14] The 2025 revenue shortfall of approximately $16.8 million related to the July 1, 2025 rate implementation date is proposed to be amortized evenly over a 30-month period from July 1, 2025 to December 31, 2027. See *Volume 1, Application, Company Evidence and Exhibits, Section 3.5.5: 2025 Revenue Shortfall.*

1 Table 4-6 provides forecast 2025 and 2026 depreciation costs.

Table 4-6:
Depreciation Costs
2025F and 2026F
($000s)

	2025F	2026F
Existing[15]	83,143	86,691
Changes	-	-
Proposed	**83,143**	**86,691**

2 Table 4-7 provides forecast 2025 and 2026 income taxes.

Table 4-7:
Income Taxes
2025F and 2026F
($000s)

	2025F	2026F
Existing	20,037	18,010
Tax Effects of Application Proposals[16]	7,429	9,531
Proposed[17]	**27,466**	**27,541**

[15] Depreciation rates are based on the *2019 Depreciation Study* approved by the Board in Order No. P.U. 3 (2022). See *Volume 1, Application, Company Evidence and Exhibits, Section 3.2.3: Depreciation*.

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

	($000s)	
	2025F	2026F
Increase in Forecast Revenue Requirement from Rates, Exhibit 7, line 21	17,455	38,879
Change in Transfers to the RSA, Exhibit 7, lines 17 and 18	(6,701)	(3,872)
Change in Taxable Revenue	10,754	35,007
Change in Tax Deductible Expenses (i.e. power supply, operating and finance charges)	1,457	6,971
Change in Taxable Income	12,211	41,978
Tax Rate	30.0%	30.0%
Change in Cash Income Taxes	3,663	12,593
Change in Deferred Income Taxes	3,766	(3,062)
Change in Total Income Taxes	**7,429**	**9,531**

[17] 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 2025 and 2026 return on rate base.

Table 4-8 summarizes the proposed 2025 and 2026 return on rate base and rate of return on rate base.

Table 4-8:
Return on Rate Base
2025F and 2026F
($000s)

	2025F	**2026F**
Forecast Average Rate Base	1,406,816[18]	1,451,200[19]
Forecast Regulated Returns		
Debt	41,002	41,016
Common Equity	63,047	63,651
Return on Rate Base	**104,049**	**104,667**
Rate of Return on Rate Base (%)	**7.40**[20]	**7.21**[21]

[18] The 2025F average rate base is shown in Exhibit 6 in *Volume 1, Application, Company Evidence and Exhibits*.
[19] The 2026F average rate base is shown in Exhibit 6 in *Volume 1, Application, Company Evidence and Exhibits.*
[20] The forecast rate of return on rate base for 2025 is calculated as ($104,049 / $1,406,816 = 7.40%), as shown in Exhibit 8 in *Volume 1, Application, Company Evidence and Exhibits.*
[21] The forecast rate of return on rate base for 2026 is calculated as ($104,667 / $1,451,200 = 7.21%), 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 2025 and 2026 deductions from revenue requirement.

Table 4-9:
Deductions from Revenue Requirement
2025F and 2026F
($000s)

	2025F	2026F
Other Revenue	(9,223)[22]	(6,860)[23]
Transfers to the RSA – ESCV	(40,165)	(35,495)
Transfers to the RSA – CDM and Electrification	(5,654)[24]	(6,042)[25]
Interest on Security Deposits[26]	72	72
Proposed	**(54,970)**	**(48,325)**

Changes in Newfoundland Power's purchased power expense related to variances in customers' load requirements from test year revenue requirements are captured by the Company's Energy Supply Cost Variance Account (the "ESCV Account").[27] Any required credit to, or recovery from, customer rates arising from energy supply cost variances are included in the Company's annual RSA adjustment.

Typically, energy supply costs are "rebased" from flowing through the annual RSA adjustment into base rate test year revenue requirements as part of general rate applications. For reasons discussed in Section *1.2.4 Wholesale Power Supply Cost*s, including uncertainty in the

22 See Exhibit 7 in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 2, line 15.
23 See Exhibit 7 in *Volume 1, Application, Company Evidence and Exhibits*, page 2 of 2, line 15.
24 Includes $5,345,000 related to the amortization of CDM program costs and $309,000 related to the amortization of Electrification costs.
25 Includes $5,659,000 related to the amortization of CDM program costs and $383,000 related to the amortization of Electrification costs. The $1,000 difference from the Electrification Costs Amortization shown in Table 4-3 is due to rounding.
26 Interest on customer security deposits is not included in the determination of revenue requirements.
27 The operation of the ESCV Account was approved in Order No. P.U. 32 (2007) and approved for continued use in Order No. P.U. 43 (2009).

implementation date of a new wholesale rate and the potential material difference in marginal energy costs, Newfoundland Power has not rebased its forecast power supply energy costs into base rate 2025 and 2026 revenue requirements. This approach will result in energy supply costs ultimately recovered from customers related to 2025 and 2026 being based on the wholesale rate actually in effect in those years.[28]

The ESCV amounts could vary materially from the forecast figures depending on the wholesale rate, including the second block energy rate, in effect in 2025 and 2026. To illustrate, Table 4-10 shows the current calculation of the 2026 ESCV amount using the current second block wholesale energy rate, which is based on the cost of fuel at Holyrood. The table also provides a comparison to a *pro forma* 2026 ESCV amount using a current estimate of 2026 marginal energy costs based on energy exports.[29]

Table 4-10:
Energy Supply Cost Illustration
2026 ESCV Calculation

	Current	**Pro Forma**
Second block wholesale rate (¢/kWh)	18.165	3.500
Average energy rate (¢/kWh)[30]	6.940	6.940
Difference (¢/kWh)	**11.225**	**(3.440)**
Energy purchases variance (GWh)[31]	316.2	316.2
ESCV amount ($000s)[32]	**35,495**	**(10,877)**

28 ESCV amounts are charged or credited annually to the RSA on December 31st and incorporated into the following year's July 1st RSA rate adjustment.

29 Based on a weighted average of marginal energy costs for 2026 included in Hydro's *Marginal Cost Projection 2024 – 2040*, dated December 31, 2022.

30 Newfoundland Power's 2023 test year average energy rate currently being used to determine ESCV amounts.

31 Variance in energy purchase requirements from the Company's 2023 test year. The variance includes 117 GWh related to the electrification of the Memorial University's boilers.

32 Determined by multiplying the energy purchases variance by the difference between the second block wholesale rate charged by Hydro and the average energy rate reflected in existing customer rates.

Table 4-10 shows that existing wholesale energy cost dynamics are such that the cost to Newfoundland Power of the additional energy supply required to serve customers is greater than the average energy supply cost reflected in customer rates.[33] The current annual shortfall is 11.2¢ per kWh and this will continue until the wholesale rate charged by Hydro to Newfoundland Power is revised to reflect marginal costs following the commissioning of the Muskrat Falls Project. Forecast marginal energy costs based on energy exports provide for an annual credit of 3.4¢ per kWh.[34] The difference in marginal costs could result in the ESCV amount being almost $50 million lower than the 2026 forecast based on the wholesale rate currently in effect.[35]

This illustration demonstrates that changing supply cost dynamics could have a material impact on the amount of the ESCV transfers in the 2025 and 2026 test years depending on the wholesale rate in effect in those years.

The same level of uncertainty and materiality is not expected with the Company's demand costs. The demand rate included in the wholesale rate has been relatively stable over time, with demand rate increases typically negotiated between Newfoundland Power and Hydro, rather than being strictly determined based on marginal cost forecasts.[36] As such, demand costs have been rebased

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33 This wholesale energy cost dynamic has existed since the ESCV mechanism was initially approved in 2007.

34 The estimated credit of 3.4¢ per kWh is based on Hydro's average energy rate of 6.940¢ per kWh less an estimated second block wholesale rate of 3.5¢ per kWh (6.940¢ per kWh – 3.500¢ per kWh = 3.440 ¢ per kWh).

35 ESCV amounts from Table 4-10. ($10,877) – $35,495 = ($46,372).

36 The demand rate has increased from $4.00/kW per month in 2007 to $5.00/kW per month in 2023. The demand rate changed three times over that timeframe: to $4.32/kW per month in 2015, to $4.75/kW per month in 2016 and to $5.00/kW per month in 2019. No demand rate change was more than 10%. The current demand charge rate was included in the settlement agreement associated with Hydro's *2017 General Rate Application*.

into 2025 and 2026 base rate revenue requirements resulting in no transfers to the RSA related to demand costs in those years.

4.3.5 Required Revenue Increase

Table 4-11 provides a forecast increase in revenue from rates of approximately $19.3 million required to meet the Company's proposed 2025 revenue requirement and approximately $44.5 million required to meet the Company's proposed 2026 revenue requirement.[37]

Table 4-11:
Required Revenue Increases
2025F and 2026F
($000s)

	2025F	2026F
Proposed Revenue From Rates	**768,770**	**789,602**
Revenue From Existing Rates[38]	(751,315)	(750,723)
Elasticity Impacts[39]	1,845	5,585
Required Increase in Revenue from Rates	**19,300**	**44,464**

The required increase in revenue from rates translates into a customer rate increase of 5.5% effective July 1, 2025.[40]

37 See Exhibit 9 in *Volume 1, Application, Company Evidence and Exhibits*, Column E.
38 Reflects customer rates proposed, with effect on July 1, 2024, in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.
39 See Exhibit 9 in *Volume 1, Application, Company Evidence and Exhibits*, Column D.
40 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 approximately 4,600, or 1.7%, from 2022 to 2026. Annual weather-adjusted energy sales are forecast to increase by approximately 194 GWh, or 3.4%, over the same period. Demand in 2026 is forecast to be 1,455.2 MW, slightly lower than Newfoundland Power's record peak demand in 2022.

The Application proposes an average increase in customer rates of 5.5% effective July 1, 2025.

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 299,000 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 2026 test year.

Table 5-1:
Newfoundland Power Customer Base
2026F

Rate	Class of Service	% of Total Customers	% of Total Energy Sales
1.1	Domestic	87.0	59.9
2.1	General Service 0-100 kW (110 kVA)	8.5	13.3
2.3	General Service 110-1000 kVA	0.5	17.9
2.4	General Service 1000 kVA and Over	- [2]	8.6
4.1	Street and Area Lighting	4.0	0.3
Total		**100.0**	**100.0**

The majority of customers served by Newfoundland Power are domestic service customers. Approximately 60% of the Company'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 make up 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 2022 and forecast for 2023F to 2026F.

Table 5-2:
Number of Customers
2022 to 2026F

	2022	**2023F**	**2024F**	**2025F**	**2026F**
Domestic	238,353	239,605	240,595	241,461	242,206
General Service					
0-100 kW (110 kVA)	23,069	23,243	23,352	23,453	23,547
110-1000 kVA	1,258	1,273	1,273	1,273	1,273
1000 kVA and Over	59	60	59	59	57[4]
Total General Service	24,386	24,576	24,684	24,785	24,877
Street and Area Lighting	11,025	11,100	11,165	11,221	11,276
Total Customers	**273,764**	**275,281**	**276,444**	**277,467**	**278,359**

The number of customers served by Newfoundland Power is forecast to increase by 0.6% in 2023, 0.4% in each of 2024 and 2025, and 0.3% in 2026. Growth in the number of Domestic customers is largely a result of housing starts and completions.

[4] It is anticipated that as some major projects wind down the number of customers with demand greater than 1,000 kVA will be reduced.

Table 5-3 shows the Company's actual energy sales for 2022 and forecast for 2023F to 2026F based on proposed customer rates.

Table 5-3:
Energy Sales Forecast
2022 to 2026F
(GWh)

	2022	**2023F**	**2024F**	**2025F**	**2026F**
Domestic	3,548.0	3,667.0	3,666.9	3,614.6	3,580.0
General Service					
0-100 kW (110 kVA)	781.3	790.7	795.5	792.6	795.1
110-1000 kVA	1,034.6	1,064.4	1,069.8	1,072.0	1,070.6
1000 kVA and Over	392.6	401.7	426.5	518.5	514.7
Total General Service	2,208.5	2,256.8	2,291.8	2,383.1	2,380.4
Street and Area Lighting	28.0	25.4	22.7	20.2	17.9
Total Energy Sales	**5,784.5**	**5,949.2**	**5,981.4**	**6,017.9**	**5,978.3**

Annual weather-adjusted energy sales are forecast to increase by approximately 0.8% per year from 2022 to 2026.

Sales to domestic service customers are forecast to increase by approximately 1.7% annually from 2022 to 2024 and decline by approximately 1.2% annually in 2025 and 2026. The forecast decline in energy sales primarily reflects the expected challenging economic conditions in Newfoundland Power's service territory[5] and the elasticity effect associated with anticipated electricity rate increases over the period.[6] The forecast energy sales also reflect conservation

[5] For example, the number of housing starts expected in the forecast period are the lowest observed by Newfoundland Power since at least 1977. See *Volume 1, Application, Company Evidence and Exhibit, Section 3: Finance,* page 3-23.

[6] For example, the sales forecast includes elasticity effects of 16 GWh in 2025 and 48 GWh in 2026 as a result of the proposed July 1, 2025 average rate increase of 5.5%.

efforts undertaken by customers, including the installation of heat pumps to offset baseboard electric heating, as well as customer electrification activities, including conversion from oil to electric heating sources and additional load from electric vehicle adoption.[7]

Sales to general service customers are forecast to increase by approximately 1.9% annually from 2022 to 2026. The forecast increase in energy sales primarily reflects higher load requirements for Memorial University following the addition of electric boilers to its oil-fired boiler system.[8]

Street and area lighting sales are forecast to decline by 10.6% annually from 2022 to 2026. The forecast decline in energy sales reflects the Company's six-year *LED Street Lighting Replacement Plan*, which will replace all HPS street light fixtures with more energy-efficient LED fixtures by 2026.

Newfoundland Power forecasts its peak demand to estimate purchased power costs from Hydro throughout the forecast period.

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[7] 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 28% in 2022.

[8] The forecast load at Memorial University is expected to reach over 40 MVA following the university's addition of electric boilers to its oil-fired boiler system. The project is being executed with funding from the provincial and federal governments to help meet net-zero objectives. See Provincial Government press release, *Provincial and Federal Governments Invest in Electrification Project at Memorial University,* March 25, 2022.

Table 5-4 shows the Company's actual demand for 2022 and forecast for 2023F to 2026F.

Table 5-4:
Demand Forecast
2022 to 2026F
(MW)

	2022	2023F	2024F	2025F	2026F
Native Peak[9]	1,462.7	1,448.2	1,476.3	1,464.9	1,455.2
Purchased[10]	1,344.7	1,318.1	1,346.2	1,334.8	1,325.2
Minimum Billing Demand[11]	1,251.1	1,251.1	1,251.1	1,251.1	1,251.1

Newfoundland Power's peak demand was 1,462.7 MW in 2022.[12] This was Newfoundland Power's highest ever peak demand and resulted in the Company's lowest system load factor in the last 15 years.[13] Newfoundland Power forecasts peak demand using a load factor-based methodology, with a five-year average load factor. Based on this methodology, Newfoundland Power's demand is forecast to be 1,455.2 MW in 2026.[14]

9 Native peak is the maximum demand served by Newfoundland Power. The 2022 native peak reflects the 2022-2023 winter season.

10 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 and applies if load curtailment was not requested by Hydro at the time of peak.

11 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 anticipated to be filed with the Board in late 2024.

12 Newfoundland Power's peak demand for the 2022-2023 winter season occurred on Saturday, February 4, 2023, at 5:45pm. Load curtailment, at the request of Hydro, was successful at reducing the peak by approximately 14.1 MW.

13 Newfoundland Power's annual peak demand for the period 2018 to 2022 was 1,439.8 MW, 1,367.3 MW, 1,299.8 MW, 1,383.1 MW, and 1,462.7 MW, respectively. Newfoundland Power's system load factor from 2018 to 2022 was 49.19%, 51.54%, 52.93%, 49.54%, and 47.12%, respectively.

14 The system load factor for 2022 was 47.12%. The five-year average system load factor used to forecast demand for the 2023 to 2026 period is 49.35%, which includes the 2022 result. See *Volume 2, Supporting Materials, Tab 3, Customer, Energy and Demand Forecast, Appendix C.*

5.3 COST OF SERVICE AND RATE DESIGN

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.[15] 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 2022 costs, adjusted to reflect current customer rates and cost of service changes related to the execution of the Company's *LED Street Lighting Replacement Plan*.[16] 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	96.5
General Service 0-100 kW (110 kVA)	2.1	107.9
General Service 110-1000 kVA	2.3	107.5
General Service 1000 kVA and Over	2.4	105.8
Street and Area Lighting	4.1	97.2

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15 Bonbright, *Principles of Public Utility Rates,* Columbia University Press, 1961, Cost of Service as the Basic Standard of Reasonableness, page 67.

16 In Order No. P.U. 3 (2022), the Board approved rates, tolls and charges as set out in Schedule A of the Application with effect for service provided on and after March 1, 2022. The *2022 Cost of Service Study* includes *pro forma* adjustments to reflect: (i) a full year impact of that rate change; (ii) changes in rates due to the RSA and MTA with effect on July 1, 2023; and (iii) the forecast cost of service once all HPS street lights fixtures have been replaced with energy-efficient LED fixtures.

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.[17] The revenue-to-cost ratio for each Class of Service is between 90% and 110%.

5.3.2 Rate Design

Newfoundland Power's current customer rates reflect the recommendations of the *Retail Rate Review* conducted in 2010.[18] The latest *Rate Design Review* commenced in 2023 and is anticipated to be completed by 2026.[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 changes to the Utility Rate structure anticipated to be filed by Hydro taking into account the impact of the Muskrat Falls Project.[21]

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17 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%."*

18 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.* In Order No. P.U. 3 (2022), the Board directed Newfoundland Power to conduct a new Load Research Study and a Retail Rate Design Review as proposed by the Company, with the costs to be charged to the deferral account. This review is anticipated to be completed by 2026.

19 Newfoundland Power's *Load Research and Rate Design Framework* was filed with the Board on December 30, 2022. In addition to the Rate Design Review, Newfoundland Power also plans to complete a review of the rates charged to Memorial University due to the anticipated large changes in their load profile in the coming years due to the planned installation of electric boilers, the addition of new buildings, and the potential establishment of a capacity assistance agreement.

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. Marginal costs on the Island Interconnected System now reflect: (i) the cost of additional on-island capacity; and (ii) the opportunity cost of exporting energy to other jurisdictions.

The Company's future embedded and marginal costs cannot reasonably be determined until Hydro files its next general rate application reflecting the changes related to the Muskrat Falls Project.[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 embedded and marginal cost outlook.[23]

The Company submits that given the uncertainty regarding Newfoundland Power's future embedded and marginal costs and the commencement of an updated *Rate Design Review*, changes to the Company's rate designs are not appropriate at this time.

5.4 PROPOSED RATES, RULES AND REGULATIONS

5.4.1 General

The revenue-to-cost ratios for each Class of Service is between 90% and 110%. As such, Newfoundland Power is proposing to apply an average increase to each class of service, to the extent possible.

The Application proposes an average increase in customer rates of 5.5% effective July 1, 2025.

Exhibit 12 in *Volume 1, Application, Company Evidence and Exhibits* includes minor wording adjustments to the Company's Rules and Regulations associated with gender inclusive language.

[22] See *Section 3.3.2 Risk Assessment* for additional information on the Muskrat Falls Project.

[23] In correspondence dated October 3, 2022, regarding *Reliability and Resource Adequacy Study Review – 2022 Update*, Hydro recommended construction of a 154 MW expansion to its Bay d'Espoir hydroelectric facility with an estimated cost of approximately $522 million to serve as a long-term backup facility and to support forecasted load growth.

5.4.2 July 1, 2025 Customer Rates

Schedule B to the Application sets out Newfoundland Power's proposed customer rates to be effective July 1, 2025 related to its 2025 and 2026 test year revenue requirements.

A report on customer rate impacts associated with the July 1, 2025 rate change 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 the Company's forecast revenue from rates to its revenue requirements for 2025 and 2026.

Exhibit 10 in *Volume 1, Application, Company Evidence and Exhibits* provides the computation of the average increase in customer rates of 5.5% proposed by the Company.

Exhibit 11 in *Volume 1, Application, Company Evidence and Exhibits* provides a comparison of Newfoundland Power's customer rates effective July 1, 2024 and its proposed customer rates effective July 1, 2025.[24]

5.4.3 Changes to Rate Components

The Application does not propose any changes to the Company's domestic, general service, or street and area lighting rate designs. All rate components are proposed to increase by the average class amount to the extent possible, while maintaining cost differentials between certain rate components

[24] Newfoundland Power's customer rates effective July 1, 2024 are based on the proposals included in the Company's *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

for Domestic,[25] Rate #2.1,[26] Rate #2.3,[27] Rate #2.4,[28] and Rate #4.1[29] to reflect differences in the cost of providing service.

[25] The Company is proposing to maintain a $5.00 per 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. Energy charges for Domestic Service Rate #1.1S customers reflect the maintenance of a 2.25¢/kWh differential.

[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. Newfoundland Power is also proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate #2.1.

[27] Newfoundland Power is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate #2.3.

[28] Newfoundland Power is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate #2.4.

[29] 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
2022 to 2026F
($000s)

Function	**Actual 2022**	**Forecast 2023**	**Forecast 2024**	**Forecast 2025**	**Forecast 2026**
Distribution	11,295	10,755	11,102	11,500	11,919
Transmission	1,143	1,142	1,171	1,200	1,231
Substations	2,317	2,344	2,421	2,511	2,604
Power Produced	4,009	4,093	4,210	4,337	4,470
Administrative and Engineering Support	8,929	9,429	9,700	10,054	10,425
Telecommunications	1,491	1,565	1,633	1,662	1,679
Environment	203	294	304	346	328
Fleet Operations and Maintenance	2,191	2,108	2,149	2,184	2,220
Electricity Supply	**31,578**	**31,730**	**32,690**	**33,794**	**34,876**
Customer Service	8,069	8,259	8,305	8,605	8,919
Energy Solutions	585	873	828	873	897
Uncollectible Bills	2,027	2,045	2,186	2,222	2,258
Customer Services	**10,681**	**11,177**	**11,319**	**11,700**	**12,074**
Information Systems	6,430	7,264	8,172	8,724	9,150
Financial Services	1,777	2,128	3,180	3,082	2,668
Corporate and Employee Services	17,850	17,765	18,856	19,010	19,903
Insurances	2,214	2,428	2,621	2,773	2,932
General	**28,271**	**29,585**	**32,829**	**33,589**	**34,653**
Gross Operating Cost	**70,530**	**72,492**	**76,838**	**79,083**	**81,603**

Newfoundland Power Inc.

Operating Costs by Breakdown
2022 to 2026F
($000s)

	Breakdown	Actual 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026
1	Regular and Standby	34,794	34,820	36,099	37,557	39,156
2	Temporary	541	665	691	721	754
3	Overtime	3,702	3,507	3,639	3,801	3,972
4	**Total Labour**	**39,037**	**38,992**	**40,429**	**42,079**	**43,882**
5						
6	Vehicle Expenses	2,184	2,101	2,142	2,177	2,212
7	Operating Materials	1,254	1,265	1,290	1,311	1,332
8	Inter-Company Charges	27	27	28	28	29
9	Plants, Substations, System Operations and Buildings	3,716	3,750	3,823	3,885	3,948
10	Travel	1,120	1,148	1,179	1,198	1,217
11	Tools and Clothing Allowance	1,372	1,384	1,411	1,434	1,458
12	Miscellaneous	1,467	1,608	1,640	1,663	1,691
13	Taxes and Assessments	1,388	1,401	1,428	1,451	1,475
14	Uncollectible Bills	2,027	2,045	2,186	2,222	2,258
15	Insurance	2,214	2,428	2,621	2,773	2,932
16	Severance and Other Employee Costs	156	157	160	163	166
17	Education, Training and Employee Fees	396	508	512	520	528
18	Trustee and Directors' Fees	687	693	760	772	785
19	Other Company Fees	2,945	3,572	5,131	4,771	4,672
20	Stationery and Copying	240	242	247	251	255
21	Equipment Rental and Maintenance	671	677	690	702	713
22	Telecommunications	1,655	1,680	1,748	1,775	1,791
23	Postage	1,282	1,221	1,209	1,207	1,203
24	Advertising	583	600	609	622	632
25	Vegetation Management	3,230	3,259	3,323	3,377	3,432
26	Computing Equipment and Software	2,879	3,734	4,272	4,702	4,992
27	**Total Other**	**31,493**	**33,500**	**36,409**	**37,004**	**37,721**
28						
29	**Gross Operating Cost**	**70,530**	**72,492**	**76,838**	**79,083**	**81,603**

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Statements of Income
($000s)

	Actual	Forecast[1]			
	2022	**2023**	**2024E**	**2025E**	**2026E**
Revenue from rates	715,444	732,809	740,817	751,315	750,723
Transfers from the RSA	6,691	36,918	41,533	52,520	45,409
Excess Earnings Account	-	(5,094)	-	-	-
	722,135	764,633	782,350	803,835	796,132
Purchased power expense	479,373	517,940	522,821	533,716	531,779
Demand management incentive account adjustments	153	(1,000)	-	-	-
	479,526	516,940	522,821	533,716	531,779
Contribution	242,609	247,693	259,529	270,119	264,353
Other revenue[2]	6,120	7,422	10,026	11,019	11,646
Other expenses:					
Operating expenses[3]	68,869	73,473	78,775	81,394	84,156
Employee future benefit costs[4]	7,652	2,763	3,010	8,122	1,812
Deferred cost recoveries and amortizations	(656)	(816)	(6,962)	492	492
Depreciation[5]	70,662	74,869	79,557	83,143	86,691
Finance charges[6]	34,790	37,313	41,607	42,240	43,427
	181,317	187,602	195,987	215,391	216,578
Income before income taxes	67,412	67,513	73,568	65,747	59,421
Income taxes[7]	19,498	20,020	22,399	20,037	18,010
Earnings applicable to common shares[7]	47,914	47,493	51,169	45,710	41,411
Rate of Return and Credit Metrics					
Rate of Return on Rate Base (%)	6.72	6.85	6.82	6.24	5.84
Regulated Return on Book Equity (%)	8.95	8.44	8.44	7.16	6.38
Interest Coverage (times)	2.5	2.4	2.4	2.2	2.0
CFO Pre-W/C + Interest / Interest (times)	4.4	3.6	2.9	2.9	2.8
CFO Pre-W/C / Debt (%)	17.4	12.9	10.2	9.6	9.0

[1] The 2024 through 2026 forecasts include the impact of the proposals in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

[2] Shown after reclassification of other contract costs and equity portion of AFUDC.

[3] Shown after adjustment for non-regulated expenses and reclassification of other contract costs and current portion of employee future benefit costs.

[4] Shown after reclassification of current portion of employee future benefit costs.

[5] Shown after reclassification of tax on cost of removal.

[6] Shown after reclassification of equity portion of AFUDC.

[7] Shown after adjustment for non-regulated expenses and reclassification of tax on cost of removal.

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Statements of Retained Earnings
($000s)

		Actual	Forecast			
		2022	**2023**	**2024E**	**2025E**	**2026E**
1	Balance - Beginning	456,123	473,611	511,425	560,890	574,736
2	Net income for the period	45,650	45,141	48,713	43,229	38,827
3	Allocation of Part VI.1 tax	735	-	752	752	752
4		502,508	518,752	560,890	604,871	614,315
5						
6	Dividends					
7	Common shares	28,897	7,327	-	30,135	30,548
8						
9	Balance - End of Period	473,611	511,425	560,890	574,736	583,767

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Balance Sheets
($000s)

		Actual	Forecast			
		2022	**2023**	**2024E**	**2025E**	**2026E**
1	**Assets**					
2	**Current Assets**					
3	Accounts receivable	69,551	79,246	73,504	73,612	72,720
4	Income taxes receivable	392	-	-	-	-
5	Materials and supplies	2,896	2,930	2,995	3,043	3,091
6	Prepaid expenses	3,738	3,782	3,866	3,928	3,990
7	Regulatory assets	5,439	31,584	56,460	58,628	61,196
8		82,016	117,542	136,825	139,211	140,997
9						
10	**Property, plant and equipment**	1,332,577	1,398,400	1,452,127	1,504,131	1,564,046
11	**Intangible assets**	48,221	65,676	63,516	66,020	66,506
12	**Regulatory assets**	309,124	319,879	337,783	342,197	343,563
13	**Defined benefit pension plans**	40,435	53,144	58,969	65,143	71,653
14	**Other assets**	1,573	1,522	1,501	1,484	1,474
15		1,813,946	1,956,163	2,050,721	2,118,186	2,188,239
16						
17						
18	**Liabilities and shareholder's equity**					
19	**Current Liabilities**					
20	Short-term borrowings	1,361	-	-	-	-
21	Accounts payable and accrued charges	96,022	103,034	97,003	97,946	97,748
22	Interest payable	6,856	8,478	8,271	8,176	9,304
23	Defined benefit pension plans	277	276	265	273	287
24	Other post-employment benefits	3,922	4,174	4,371	4,579	4,518
25	Regulatory liabilities	15,196	(1,768)	-	-	-
26	Current instalments of long-term debt	27,550	8,450	8,450	36,885	9,050
27		151,184	122,644	118,360	147,859	120,907
28						
29	**Regulatory liabilities**	205,003	213,716	227,876	243,992	259,648
30	**Defined benefit pension plans**	5,074	5,228	5,402	5,574	5,738
31	**Other post-employment benefits**	62,594	63,356	64,029	64,598	65,330
32	**Other liabilities**	1,270	1,562	1,544	1,526	1,508
33	**Deferred income taxes**	189,292	204,333	203,969	200,486	198,395
34	**Long-term debt**	655,597	763,578	798,330	809,094	882,625
35						
36						
37						
38	**Shareholder's equity**					
39	**Common shares**	70,321	70,321	70,321	70,321	70,321
40	**Retained earnings**	473,611	511,425	560,890	574,736	583,767
41		543,932	581,746	631,211	645,057	654,088
42		1,813,946	1,956,163	2,050,721	2,118,186	2,188,239

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Statements of Cash Flows
($000s)

		Actual	Forecast			
		2022	**2023**	**2024E**	**2025E**	**2026E**
1	**Operating Activities**					
2	Net Earnings	45,650	45,141	48,713	43,229	38,827
3						
4	**Items Not Affecting Cash:**					
5	Depreciation of property, plant and equipment	73,712	76,456	81,351	84,988	88,568
6	Amortization of intangible assets and other	4,690	6,515	6,724	7,070	7,427
7	Change in long-term regulatory assets and liabilities	2,880	(33,891)	(46,611)	(47,556)	(46,530)
8	Deferred income taxes	(3,053)	14,082	(364)	(3,483)	(2,091)
9	Employee future benefits	(3,818)	(6,906)	(7,220)	(2,418)	(5,576)
10	Other	60	(1,077)	174	145	(11)
11		120,121	100,320	82,767	81,975	80,614
12						
13	Change in working capital	(12,080)	(26,603)	10,005	38,770	44,189
14		108,041	73,717	92,772	120,745	124,803
15						
16	**Investing Activities**					
17	Capital expenditures	(110,218)	(133,812)	(125,493)	(122,769)	(134,564)
18	Intangible asset expenditures	(16,774)	(23,752)	(4,339)	(9,353)	(7,695)
19	Contribution from customers and security deposits	2,773	3,500	2,500	2,500	2,500
20	Other	-	380	-	-	-
21		(124,219)	(153,684)	(127,332)	(129,622)	(139,759)
22						
23	**Financing Activities**					
24	Change in short-term borrowings	(13,459)	(1,361)	-	-	-
25	Net proceeds (repayment) of committed credit facility	20,000	7,634	43,010	47,462	(16,511)
26	Proceeds from long-term debt	75,000	90,000	-	-	100,000
27	Repayment of long-term debt	(35,950)	(8,450)	(8,450)	(8,450)	(37,485)
28	Payment of debt financing costs	(516)	(529)	-	-	(500)
29	Dividends on Common Shares	(28,897)	(7,327)	-	(30,135)	(30,548)
30		16,178	79,967	34,560	8,877	14,956
31						
32	**Change in Cash**	-	-	-	-	-
33	**Cash, Beginning of Year**	-	-	-	-	-
34	**Cash, End of Year**	-	-	-	-	-

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Average Rate Base[1]
($000s)

	Actual	Forecast			
	2022	2023	2024E	2025E	2026E
Plant Investment	1,204,059	1,264,037	1,334,567	1,381,842	1,425,802
Additions to Rate Base					
Defined Benefit Pension Costs	91,992	98,264	104,719	108,876	112,167
Deferred Credit Facility Costs	92	96	90	59	31
Cost Recovery Deferral - Conservation	17,890	20,223	21,473	22,010	22,242
Cost Recovery Deferral - 2022 Revenue Shortfall	230	344	115	-	-
Cost Recovery Deferral - 2024 Revenue Shortfall	-	-	2,353	4,706	4,706
Cost Recovery Deferral - Load Research and Retail Rate Design	10	174	513	800	902
Cost Recovery Deferral - Pension Capitalization	-	400	997	1,020	672
Demand Management Incentive Account	617	297	350	-	-
Customer Finance Programs	1,614	1,443	1,421	1,435	1,450
	112,445	121,241	132,031	138,906	142,170
Deductions from Rate Base					
Weather Normalization Reserve	4,298	2,091	(1,198)	-	-
Other Post-Employment Benefits	76,859	81,955	85,517	89,012	90,703
Customer Security Deposits	1,336	1,270	1,270	1,270	1,270
Accrued Pension Obligation	5,234	5,377	5,535	5,706	5,885
Accumulated Deferred Income Taxes	17,026	25,045	33,177	35,249	37,782
Excess Earnings Account	-	1,783	3,566	3,566	3,566
Refundable Investment Tax Credits	-	146	283	265	247
	104,753	117,667	128,150	135,068	139,453
Average Rate Base Before Allowances	1,211,751	1,267,611	1,338,448	1,385,680	1,428,519
Cash Working Capital Allowance	6,705	7,419	7,705	7,865	7,829
Materials and Supplies Allowance	11,978	14,676	13,905	14,164	14,389
Average Rate Base at Year End	1,230,434	1,289,706	1,360,058	1,407,709	1,450,737

[1] All amounts shown are averages.

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Weighted Average Cost of Capital
($000s)

		Actual	Forecast			
		2022	**2023**	**2024E**	**2025E**	**2026E**
1	**Average Capitalization**					
2	Debt	661,762	728,164	789,314	826,322	868,798
3	Common Equity	535,188	562,839	606,479	638,134	649,573
4		1,196,950	1,291,003	1,395,793	1,464,456	1,518,371
5						
6	**Average Capital Structure (%)**					
7	Debt	55.29	56.40	56.55	56.43	57.22
8	Common Equity	44.71	43.60	43.45	43.57	42.78
9		100.00	100.00	100.00	100.00	100.00
10						
11	**Cost of Capital (%)**					
12	Debt[1]	5.25	5.11	5.26	5.10	4.99
13	Common Equity	8.95	8.44	8.44	7.16	6.38
14						
15						
16	**Weighted Average Cost of Capital (%)**					
17	Debt	2.90	2.88	2.98	2.88	2.86
18	Common Equity	4.00	3.68	3.67	3.12	2.73
19		6.90	6.56	6.65	6.00	5.59

[1] 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 2022 Annual Reports to the Board can be reconciled to the reported cost of debt above as follows:

	2022
Cost of Debt (Line 14) (%)	5.25
AFUDC (%)	0.23
Cost of Debt - Return 25 (%)	5.48

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Rate of Return on Rate Base
($000s)

		Actual	Forecast			
		2022	**2023**	**2024E**	**2025E**	**2026E**
1	Regulated Return on Equity	47,914	47,493	51,169	45,710	41,411
2	Excess Earnings Account	-	3,566	-	-	-
3		47,914	51,059	51,169	45,710	41,411
4						
5	Finance Charges					
6	Interest on Long-Term Debt	35,597	36,677	39,053	38,600	40,860
7	Other Interest	453	2,736	3,541	4,695	3,972
8	Amortization of Bond Issue Expenses	215	221	225	221	217
9	AFUDC	(1,498)	(2,393)	(1,285)	(1,350)	(1,696)
10		34,767	37,241	41,534	42,166	43,353
11						
12	Return on Rate Base	82,681	88,300	92,703	87,876	84,764
13						
14	Average Rate Base	1,230,434	1,289,706	1,360,058	1,407,709	1,450,737
15						
16	Rate of Return on Rate Base (%)	6.72	6.85	6.82	6.24	5.84

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Inputs and Assumptions

Energy Forecasts: Energy forecasts are based on economic indicators taken from the Conference Board of Canada Economic Forecast, dated August 2, 2023.

Revenue Forecast: The revenue forecast is based on the Customer, Energy and Demand forecast dated September 14, 2023.

Revenue for 2022 through 2024 forecast 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 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. 8 (2011), P.U. 13 (2013), P.U. 18 (2015), and P.U. 3 (2022).

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 September 14, 2023.

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.

Employee Future Benefit Costs: Pension funding is based on the actuarial valuation dated as at December 31, 2022.

Pension discount rate is 3.20% for 2022, 5.30% for 2023 and 4.80% for 2024 through 2026.

Expected return on pension plan assets is 4.50% for 2022 and 5.75% for 2023 through 2026.

OPEBs discount rate is 3.20% for 2022 and 5.30% for 2023 through 2026.

Cost Recovery Deferrals: The 2023 through 2026 forecasts include the deferred recovery over a 10-year period of certain Conservation program costs.

The 2023 and 2024 forecasts include the amortization over a 34-month period of a $0.9 million revenue shortfall beginning March 1, 2022 related to a March 1, 2022 rate implementation date.

The 2023 through 2026 forecasts include deferral of Electrification costs, including applicable interest.

The 2023 through 2026 forecasts include the deferral of costs related to the Load Research Study and Retail Rate Design Review.

The 2023 through 2026 forecasts include the deferral of $5.1 million in revenue related to forecast Excess Earnings in 2023.

The 2024 through 2026 forecasts include the deferral of a $6.7 million revenue shortfall related to a July 1, 2024 rate implementation date proposed in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

Newfoundland Power Inc.

Financial Performance
2022 to 2026E
Inputs and Assumptions

Cost Recovery Deferrals (cont'd):	The 2023 through 2026 forecasts include the amortization over a 60-month period of $1.4 million in income tax impacts beginning on January 1, 2023 related to the change in pension capitalization approved in the *2022/2023 General Rate Application.* The 2024 through 2026 forecasts include the amortization over a 60-month period of $1.1 million in income tax impacts beginning on January 1, 2024 related to the change in pension capitalization approved in the *2022/2023 General Rate Application.*
Depreciation Rates:	Depreciation rates are based on the *2019 Depreciation Study.*
Operating Costs:	The operating forecast for 2023 reflects the most recent management estimates. Operating forecasts for 2024 through 2026 reflect projected labour increases of 3.80% in 2024, 4.45% in 2025 and 4.50% in 2026, and non-labour increases based upon the GDP deflator.
Capital Expenditures:	Capital Expenditures for 2023 are based on the *2023 Capital Budget Application,* adjusted for known carryovers, and the *2023 Supplemental Capital Expenditure Application.* Capital Expenditures for 2024 through 2026 are based on the *2024 Capital Budget Application* and the *2023 Supplemental Capital Expenditure Application.*
Short-Term Interest Rates:	Average short-term interest rates are forecast to be 5.97% for 2023, 5.54% for 2024 and 4.75% for 2025 and 2026.
Long-Term Debt:	A $90.0 million long-term debt issue was completed in August 2023. The debt was issued for 30 years at a coupon rate of 5.122%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt. A $100.0 million long-term debt issue is forecast to be completed in March 2026. The debt is forecast for 30 years at a coupon rate of 5.50%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.
Dividends:	Common share 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 2023 through 2026.

Credit Rating Reports:
Moody's and DBRS

MOODY'S
INVESTORS SERVICE

CREDIT OPINION

31 March 2023

Update

Send Your Feedback

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.

Contacts

Gavin MacFarlane +1.416.214.3864
VP-Sr Credit Officer
gavin.macfarlane@moodys.com

Yifei Qin +1.647.417.6291
Associate Analyst
yifei.qin@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Newfoundland Power Inc.

Update to credit analysis

Summary

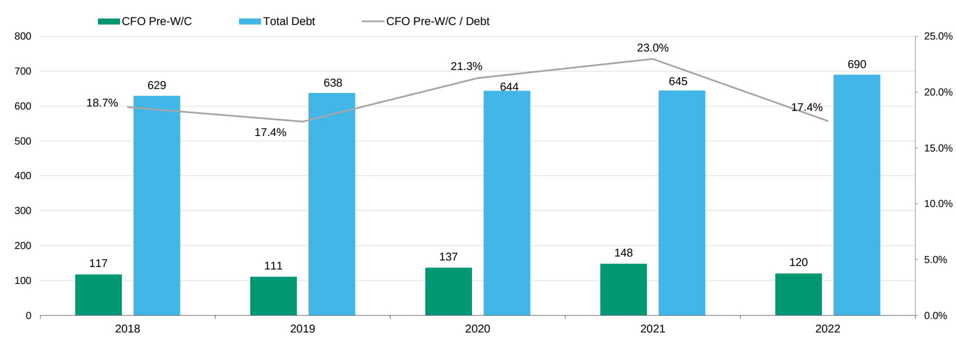
Newfoundland Power Inc.'s (NPI, Baa1 stable) credit profile reflects the company's low business risk as a primarily electric transmission and distribution cost-of-service regulated utility with no unregulated business activities. Approximately 93% of NPI's power requirements are purchased from provincially owned Newfoundland & Labrador Hydro (NL 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 February 2022 PUB order on the company's General Rate Application maintained the company's allowed Return on Equity (ROE) at 8.5% and 45% equity capital for the period 2022-2024.

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 significant 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.

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 full completion of Muskrat Falls and related projects expected in 2023

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%. 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]

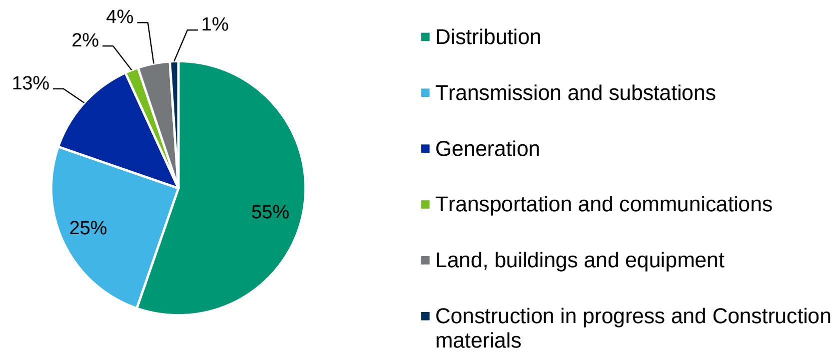
	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22
CFO Pre-W/C + Interest / Interest	4.2x	4.0x	4.7x	5.2x	4.4x
CFO Pre-W/C / Debt	18.7%	17.4%	21.3%	23.0%	17.4%
CFO Pre-W/C – Dividends / Debt	14.3%	13.0%	14.0%	17.8%	13.2%
Debt / Capitalization	48.8%	48.1%	48.2%	47.6%	48.5%

[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 and Labrador, NPI is primarily an electric transmission distribution utility serving a customer base of approximately 274,000. 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 NL Hydro (not rated) which is indirectly held, but wholly owned by the Province of Newfoundland and 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
2022 Net Property, Plant and Equipment by segment
Newfoundland Power Inc.



Source: NPI's 2022 MD&A

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 system 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, although at times they have been below forecast as electricity sales declined from 2016 to 2021 before increasing 1.2% in 2022. Growth in rate base over this time 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 2022. The majority of generation assets are low risk small scale hydro electric generation. 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 directly exposed to commodity price risk and the operational, financial and environmental risks associated with electricity generation.

NPI faces uncertainties due to the timing and size of expected rate increases associated with the Province's Muskrat Falls hydroelectric project. The total cost of Muskrat Falls and associated transmission in Newfoundland and Labrador has increased to about CAD13.4 billion and this may increase. The size of the project and associated rate increases are exacerbated by the relatively small size of NPI and the Newfoundland and Labrador economy. The 824 MW hydro electric project was completed in November 2021, however the Labrador Island Link (LIL) a key transmission project, is still not yet fully commissioned although it is transmitting some power. The LIL has not passed high power testing that would enable it to operate at its design capacity. The entire project, including the LIL, needs to be fully commissioned before it goes into rates. Nonetheless, NL Hydro's Project Cost Recovery Rider began to recover some of the costs of Muskrat Falls from customers on 1 July 2022. This 6.1% increase in rates largely offset a 6.4% decline in rates that would have otherwise occurred at that time due to the normal functioning of the Rate Stabilization Plan (RSP).

NL Hydro continues to work with the Province towards a rate mitigation plan that will clearly include ongoing federal government support. 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 resulting in lower revenues and cash flow. Rate impacts from the project will likely begin to impact bills in a more pronounced manner about a year after the project is fully commissioned, although if the project is fully commissioned in the next few weeks then the NL Hydro Project Cost Recovery Rider would grow significantly on 1 July 2023. Key areas of analytical focus include details of the rate mitigation plan as well as rate structure and design. For context, inclusive of potential investments to improve reliability, rates could grow to about 20 cents/kWh from about 13 cents/kWh within 10 years.

Supportive regulatory environment

NPI's operations benefit from a well-developed regulatory framework and business environment that we consider credit supportive. The 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. The company has not been subject to political interference. NPI has access to the courts to address disputes with the PUB although the company has not pursued legal remedies in at least 20 years.

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 with the most recent plan approved on 20 December 2022 allowing capex of CAD123 million in 2023. 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 the capital program. The company reached a rate case settlement on 22 November 2021 for the period 2022-2023 and it was approved by the PUB in the first quarter of 2022. NPI's allowed ROE of 8.5% for the period 2022-2023 remains unchanged. While the ROE remains relatively low, it is mitigated by one of the highest deemed equity levels in Canada that remains unchanged at 45%.

Exhibit 4

Historical Approved ROE, Approved Equity thickness and Rate Base

Newfoundland Power Inc.

	2016	2017	2018	2019	2020	2021	2022	2023F
Approved Return on Equity (ROE)	8.5%	8.5%	8.5%	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	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3

Source: Fortis Inc's presentations, NPI's 2022-2023 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 its predictable cash flow is depreciation and amortization. Following the rate case we continue to forecast CFO pre-W/C to debt in the 16-18% range, consistent with the current credit profile. Financial metrics may fluctuate, however the variability is primarily a function of changes in long term regulatory assets and liabilities that is unlikely to be sustained over time, as shown in the table below. The company forecasts annual capital investments of about CAD130 million over the period 2023 to 2027 and we expect the company to continue to file regular cost of service rate applications to ensure timely recovery of costs.

Exhibit 5
Historical CFO Pre-W/C Breakdown
Newfoundland Power Inc.

(in CN$ Millions)	FYE Dec-17	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-22
As Adjusted						
Net Income	**41.0**	**41.2**	**42.3**	**43.6**	**43.8**	**45.7**
Depreciation	59.9	62.0	64.6	67.3	69.7	73.7
Amortization of Investments	3.3	3.4	3.6	4.1	4.5	4.7
Deferred income taxes and itc	2.3	(2.9)	5.2	(5.1)	0.9	(3.1)
Other	2.6	2.7	(2.3)	2.9	3.5	(3.8)
Funds from Operations	**109.0**	**106.4**	**113.5**	**112.8**	**122.4**	**117.2**
Changes in Other Oper. Assets & Liabilities - LT	0.5	11.0	(2.8)	24.0	25.7	2.9
CFO Pre-W/C	**109.6**	**117.4**	**110.7**	**136.8**	**148.1**	**120.1**

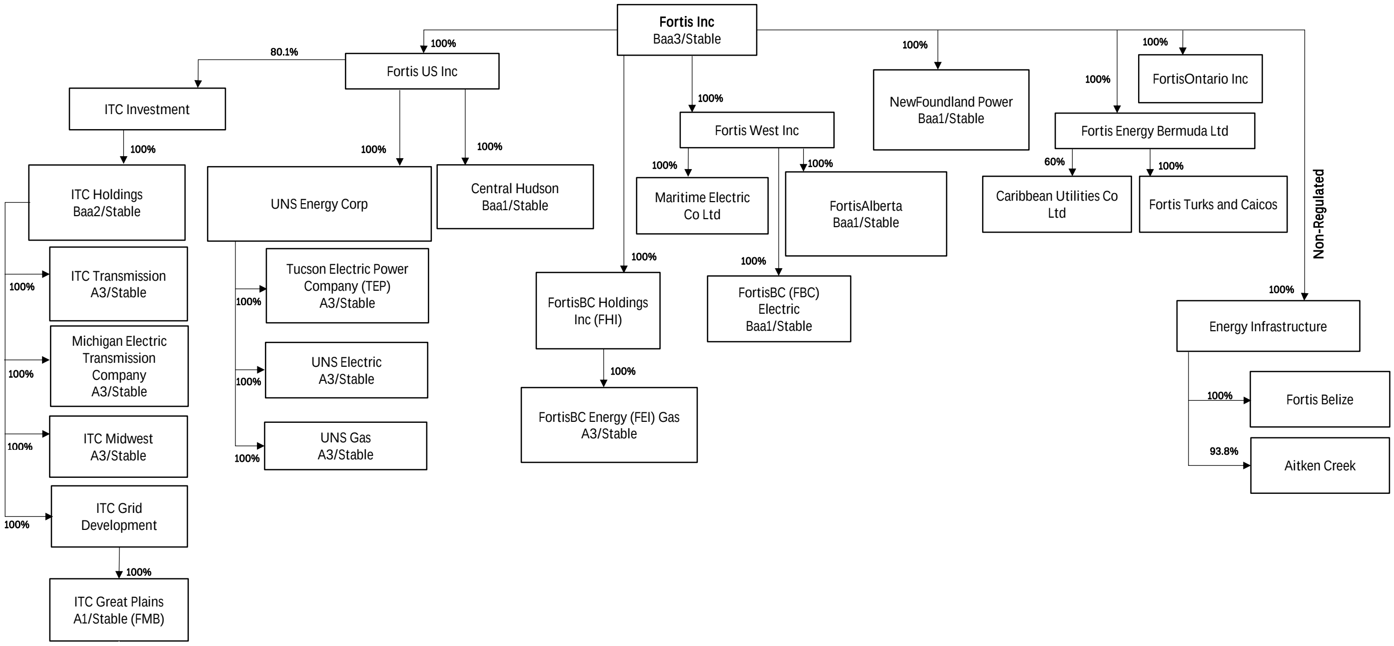
All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Regulatory liabilities in 2020 and 2021 grew in part due to marginally lower demand than forecast. The marginal cost of power that NPI obtains from Hydro exceeds the average supply costs embedded in customer rates. Sales were below forecast and the supply cost embedded in customer rates exceeded the price at which NPI purchases power, which led to growth in the company's regulatory liabilities. These pricing dynamics may change following the in-service of Muskrat Falls.

NPI is independent of Fortis Inc.

We consider NPI to be operationally and financially independent of ultimate parent FTS. 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. However, FTS has very high leverage and material holding company debt that adds financial risk across the entire FTS corporate family. FTS is dependent upon its many subsidiaries, including NPI, to make distributions to service its obligations. Despite this leverage, we view FTS ownership as generally credit positive for NPI since it benefits from access to a large and diversified parent that may facilitate streamlining operations and costs and provides strong access to capital markets. The company may periodically rely on its parent for equity injections to maintain its capital structure in line with the regulator's established parameters. We expect that FTS would provide extraordinary support to NPI, if required, provided that the parent had the economic incentive to do so. We believe that the parent will continue to have sufficient resources to provide support, if required. As of 31 December 2022, FTS had about CAD1.3 billion unused committed revolving credit facility at the FTS corporate level. Our view of parent FTS does not constrain the credit profile of NPI.

Exhibit 6
Fortis Inc's organizational structure



Source: Fortis Inc.

ESG considerations

NPI's ESG Credit Impact Score is Moderately Negative CIS-3

Exhibit 7
ESG Credit Impact Score

CIS-3

Moderately Negative

For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

NPI's ESG credit impact score is moderately negative (**CIS-3**), indicating that its ESG attributes are considered to be having an overall limited impact on the current rating, with potential for future negative impact over time. The scores reflect a combination of moderately negative exposure to environmental risks, highly negative exposure to social risks and neutral to low exposure to governance risks.

Exhibit 8
ESG Issuer Profile Scores

Source: Moody's Investors Service

Environmental

NPI's moderately negative environmental risk (**E-3** issuer profile score) is driven primarily by its exposure to physical climate risks, mostly in the form of extreme weather events including storms which is a challenge for the sector. NPI has neutral to low exposure to carbon transition risks since 93% of its power is purchased from NL Hydro and just 13% of its PP&E is comprised of generation assets, the majority of which are small hydro. The company has neutral-to-low exposure to natural capital and waste and pollution risks.

Social

NPI's exposure to social risks is highly negative (**S-4** issuer profile score). The company is exposed to increased social risks, mostly in the form of demographic and social trends. This relates to potential issues of rate shock related to the full commissioning of Muskrat Falls and the potential impact it may have on demand for electricity and on the company's cash flow.

Governance

NPI's governance is driven by that of its parent FTS. NPI's governance risk is broadly in line with other utilities and does not pose a particular risk (**G-2** issuer profile score). This is supported by a key financial policy to maintain the capital structure established by the regulator with any dividends paid to the parent offset by sufficient equity injections to maintain the target capital structure. NPI's management credibility and track record also support the low risk governance outcome. NPI's governance is driven by that of its parent FTS.

ESG Issuer Profile Scores and Credit Impact Scores for NPI are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for NPI on MDC and view the ESG Scores section.

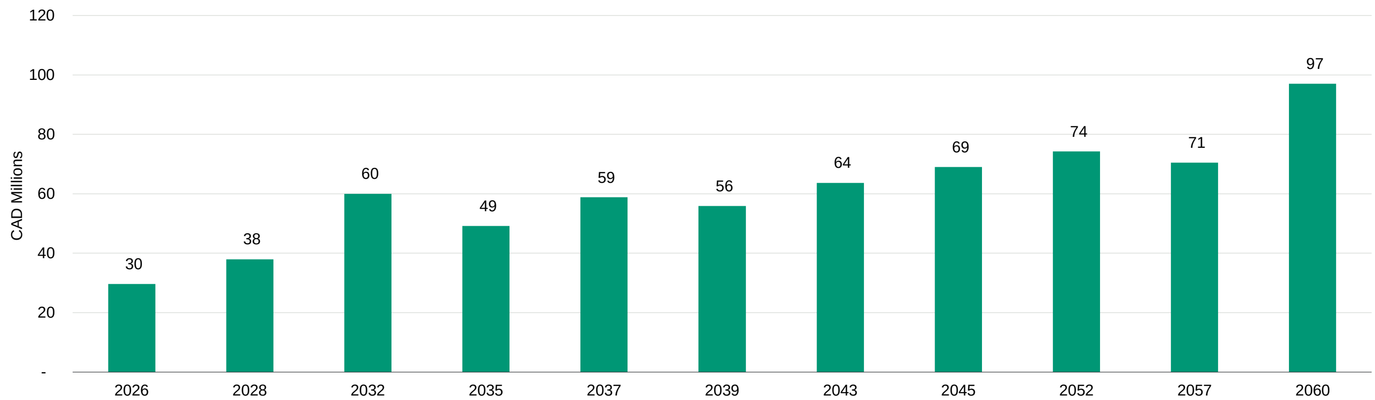
Liquidity analysis

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 around CAD123 million on capital expenditures in 2023 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 CAD110-120 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 2027. 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 $20 million drawn under the committed facility at 31 December 2022. The company does not have significant debt maturity in 2023.

Exhibit 9
Long-term Debt Maturity as of 31 December 2022
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 10
Methodology Scorecard Factors
Newfoundland Power Inc.

Regulated Electric and Gas Utilities Industry Scorecard[1][2]	Current FY 12/31/2022		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	Ba	Ba	Ba	Ba
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)	4.7x	A	4x - 5x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.5%	A	16% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.0%	Baa	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	48.1%	A	46% - 49%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A3		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 12/31/2022;
[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 11

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22
As Adjusted					
FFO	**106**	**113**	**113**	**122**	**117**
+/- Other	11	-3	24	26	3
CFO Pre-WC	**117**	**111**	**137**	**148**	**120**
+/- ΔWC	-5	13	9	-7	-12
CFO	**113**	**124**	**146**	**141**	**108**
- Div	27	28	46	33	29
- Capex	101	113	102	119	127
FCF	**-16**	**-17**	**-2**	**-12**	**-48**
(CFO Pre-W/C) / Debt	18.7%	17.4%	21.3%	23.0%	17.4%
(CFO Pre-W/C - Dividends) / Debt	14.3%	13.0%	14.0%	17.8%	13.2%
FFO / Debt	16.9%	17.8%	17.5%	19.0%	17.0%
RCF / Debt	12.6%	13.5%	10.3%	13.8%	12.8%
Revenue	664	684	719	713	736
Interest Expense	37	37	37	35	36
Net Income	26	40	44	43	40
Total Assets	1,628	1,703	1,720	1,764	1,814
Total Liabilities	1,128	1,188	1,204	1,238	1,270
Total Equity	500	515	516	526	544

[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 12

Peer Comparison Table [1]

	Newfoundland Power Inc. Baa1 (Stable)			FortisAlberta Inc. Baa1 (Stable)			Hydro One Inc. A3 (Stable)		
(In CAD millions)	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-20	FYE Dec-21	LTM Sep-22
Revenue	719	713	736	653	708	751	7,250	7,185	7,657
CFO Pre-W/C	137	148	120	394	366	386	1,874	2,039	2,230
Total Debt	644	645	690	2,391	2,409	2,568	15,644	15,010	14,911
CFO Pre-W/C + Interest / Interest	4.7x	5.2x	4.4x	4.8x	4.4x	4.5x	4.5x	4.8x	5.1x
CFO Pre-W/C / Debt	21.3%	23.0%	17.4%	16.5%	15.2%	15.0%	12.0%	13.6%	15.0%
CFO Pre-W/C – Dividends / Debt	14.0%	17.8%	13.2%	13.1%	11.6%	11.1%	8.1%	9.4%	10.6%
Debt / Capitalization	48.2%	47.6%	48.5%	55.4%	54.5%	55.1%	58.9%	56.5%	54.9%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Exhibit 13

Newfoundland Power Inc. Moody's - Adjusted Debt Breakdown

(CAD Millions)	FYE Dec-17	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-22
As Reported Debt	**597.3**	**612.3**	**570.3**	**638.2**	**639.2**	**684.5**
Pensions	6.3	5.5	5.6	5.6	5.4	5.4
Hybrid Securities	8.9	8.9	8.8	0.0	0.0	0.0
Non-Standard Adjustments	2.8	2.6	52.9	0.0	0.0	0.0
Moody's Adjusted Debt	**615.3**	**629.3**	**637.7**	**643.8**	**644.6**	**689.9**

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 14

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

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Rating Report
Newfoundland Power Inc.

DBRS Morningstar
October 28, 2022

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Erik Diehl
+1 646 870-1888
erik.diehl@dbrsmorningstar.com

Tom Li
+1 416 597-7378
tom.li@dbrsmorningstar.com

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
First Mortgage Bonds	A	Confirmed	Stable

Rating Update

On October 4, 2022, DBRS, Inc. (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. Effective March 1, 2022, the PUB approved an effective decrease of 1.1% in electricity rate charges to customers, and the Company is required to file its next General Rate Application (GRA) on or before June 1, 2024.

DBRS Morningstar considers the biggest challenge Newfoundland Power faces to be the potential rate shock for ratepayers from the Muskrat Falls project, an 824-megawatt hydroelectric generating facility developed by Nalcor Energy that is expected to be fully commissioned by the end of 2022. The full commissioning of the Muskrat Falls Project is dependent on the testing and commissioning of control software associated with the Labrador Island Link (LIL) transmission line from Muskrat Falls in Labrador to Soldiers Pond on Newfoundland's southeast coast. At project completion, 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. In February 2022, the Province of Newfoundland and Labrador (the Province; rated A (low) with a Stable trend by DBRS Morningstar) and the Government of Canada (rated AAA with a Stable trend by DBRS Morningstar) finalized an agreement for the financial restructuring of the Muskrat Falls project. The new agreement involves term sheets for a $1 billion federal loan guarantee and a $1 billion investment by the Government of Canada in the Province's portion of the LIL. The timing and the final impact the agreement will have on customer rates remains uncertain. Although DBRS Morningstar views this as a positive development, the uncertainty on future rates remains. DBRS Morningstar will continue to monitor the situation and treat a potential rate shock as an event risk.

DBRS Morningstar views weak provincial economic conditions with high dependence on volatile commodity prices as another challenge because it could significantly affect the affordability for Newfoundland Power's customers. The Province's economic and fiscal performance heavily depend on the resource sector, with resource royalties accounting for between 8% and 31% of government revenue over the past decade. This figure does not include a meaningful amount of other revenue indirectly derived from related activities. However, DBRS Morningstar notes that provincial economic conditions have improved compared with the previous year because of higher oil prices and high vaccination rates. Nevertheless, 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 2022 and for the last 12 months (LTM) ended June 30, 2022. The Company's earnings and cash flow from operations have largely remained steady year over year (YOY), reflecting the stable nature of its operations. Newfoundland Power is expected to have moderate free cash flow deficits for the next few years because of the maintenance and growth capital spending along with dividend payout. 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, which is still awaiting completion. Although unlikely, if ratepayers' ability to pay bills or Newfoundland Power's ability to fully pass on costs is negatively affected, DBRS Morningstar may downgrade the Company's ratings by multiple notches. As of July 1, 2022, Newfoundland Power customers started paying for a portion of Muskrat Falls Project related costs through Hydro's Muskrat Falls Project Cost Recovery Rider. Full recovery of Muskrat Falls Project costs will occur following the finalization of all Muskrat Falls Rate Mitigation plans and Hydro's next GRA.

Financial Information

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
Newfoundland Power Inc.	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**	**2018**	**2017**
Total debt in capital structure (%)	55.8	54.9	55.8	54.8	55.3	54.1	54.5	54.6
Cash flow/total debt (%)	15.9	17.5	17.9	19.1	17.7	18.4	17.5	18.3
EBIT gross interest coverage (times)	2.30	2.46	2.59	2.67	2.60	2.54	2.58	2.72
(CFO + interest)/(interest + sinking fund payment)	4.87	5.05	3.59	3.64	3.32	3.46	3.32	3.42

Issuer Description

Newfoundland Power is a regulated utility that primarily distributes but also generates and transmits electricity to approximately 273,000 customers throughout the island portion of Newfoundland and Labrador. The Company is a subsidiary of Fortis Inc. (rated A (low) with a Stable 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 Stable 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 its reasonable financial leverage and stable cash flow. For the LTM ended June 30, 2022, Newfoundland Power's total debt in the capital structure remained low at 55.8%, while its cash flow-to-debt and EBIT interest coverage ratios remained solid at 17.9% and 2.59 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 YOY.

Challenges

1. Uncertainty about rate shock from the Muskrat Falls project

The Muskrat Falls project is an 824-megawatt hydroelectric generating facility developed by Nalcor (100% owned by the Province). The latest estimate for the total cost for the project had gone up to $13.4 billion from $13.1 billion as estimated in February 2022, and it is currently uncertain how costs for the project will be recovered from Newfoundland Power's customers. Based on current projections, without any rate mitigation, rates are expected to increase to 22.9 cents per kilowatt hour (kWh) in 2022 (13.5 cents/kWh in 2021). DBRS Morningstar notes that in February 2022, the Province and the Government of Canada finalized an agreement for the financial restructuring of the Muskrat Falls project. Although DBRS Morningstar views this as a positive development regarding the potential relief that will be provided to ratepayers, the uncertainty on future rates remains. Should the upward pressure on rates affect the Company's ability to pass on costs, this would negatively affect its credit profile. DBRS Morningstar continues to monitor the situation and treats a potential rate shock as an event risk.

2. Weak economic outlook and limited population growth

DBRS Morningstar views weak provincial economic conditions with high dependence on volatile commodity prices as another challenge because it could significantly affect the affordability for Newfoundland Power's customers. In 2020, the coronavirus pandemic and low oil prices severely affected the provincial economy. The monthly unemployment rate spiked to 17.9% in June 2020 from 12.4% in February 2020. However, DBRS Morningstar notes that provincial economic conditions have improved compared with the previous year because of higher oil prices and high vaccination rates. Additionally, electricity consumption growth in the province is largely driven by growth in the customer base, which depends 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 led to widespread blackouts. DBRS Morningstar notes that after the Muskrat Falls project's commissioning, approximately 35% to 40% of the peak demand will be served from the mainland via the LIL. As a result, the reliability of the LIL will become very critical for the Company's power supply. The LIL is a 1,100-kilometer transmission line between the Muskrat Falls project and the Avalon Peninsula on the island of Newfoundland. DBRS Morningstar also notes there are currently reliability concerns of the LIL as Hydro is proposing additional generating capacity on the island, which could lead to further rate implications. This is currently under review by the PUB.

Earnings and Outlook

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
(CAD millions where applicable)	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**	**2018**	**2017**
Net revenues	123	120	255	252	250	239	237	232
EBITDA	80	80	170	170	169	162	160	161
EBIT	42	44	93	96	98	94	95	98
Gross interest expense	18	18	36	36	38	37	37	36
Earnings before taxes	24	24	56	55	55	54	54	54
Net income before nonrecurring items	20	19	45	44	44	43	42	42
Reported net income	20	19	45	44	44	43	42	42
Actual return on equity (%)	7.5	7.3	8.5	8.4	8.4	8.3	8.3	8.4
Regulated rate base	N/A	N/A	N/A	1,203	1,182	1,154	1,117	1,092

2021 Summary

- EBITDA remained flat in 2021 when compared with 2020. Although electricity revenues decreased by \$6.1 million in 2021, purchased power expenses were \$7.5 million lower than 2020 because of lower energy purchases and lower electricity system losses.
- Net income has consistently increased since 2016, reflecting the growing rate base.

2022 Summary/Outlook

- DBRS Morningstar expects relatively stable financial performance in 2022 because the Company operates a critical infrastructure.
- Financial metrics remained relatively flat for the LTM ended June 30, 2022. Revenue increased for the second quarter. Year-to-date periods primarily reflect higher electricity sales and changes in regulatory deferrals and amortizations, partially offset by a 1.1% decrease in customer electricity rates effective March 1, 2022, as a result of the 2022/2023 GRA Order.

Financial Profile

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
(CAD millions where applicable)	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**	**2018**	**2017**
Net income before nonrecurring items	20	19	45	44	44	43	42	42
Depreciation & amortization	39	36	77	74	71	68	65	63
Deferred income taxes and other	(5)	0	(1)	4	(2)	3	(0)	5
Cash flow from operations[1]	54	55	120	122	113	114	107	110
Dividends paid	(14)	(14)	(34)	(33)	(46)	(28)	(28)	(39)
Capital expenditures	(58)	(47)	(128)	(117)	(100)	(105)	(99)	(92)
Free cash flow (bef. working cap. changes)	(19)	(6)	(41)	(28)	(33)	(19)	(20)	(21)
Changes in noncash work. cap. items	(29)	4	(14)	19	33	10	6	0
Net free cash flow	(48)	(2)	(55)	(9)	(0)	(8)	(14)	(21)
Net equity change	0	0	0	0	(9)	(0)	(0)	(0)
Net debt change	49	(6)	55	1	18	8	15	21
Other	(0)	8	(1)	8	(8)	(0)	(1)	(0)
Change in cash	0	(0)	0	0	0	(0)	0	(0)
Total debt	673	632	673	639	638	621	612	597
Total debt in capital structure (%)	55.8	54.9	55.8	54.8	55.3	54.1	54.5	54.6
Cash flow/total debt (%)	15.9	17.5	17.9	19.1	17.7	18.4	17.5	18.3
EBIT gross interest coverage (times)	2.30	2.46	2.59	2.67	2.60	2.54	2.58	2.72
Dividend payout ratio (%)	73.2	75.2	75.6	76.5	106.5	65.8	66.6	93.9

1 Excluding cash change due to regulatory mechanism.

2021 Summary

- Newfoundland Power’s key credit metrics remained supportive of the “A” ratings in 2021.
- DBRS Morningstar adjusted cash flow from operations for 2021 is slightly higher than 2020 because of deferred taxes and depreciation.
- Similar to previous years, the majority of capital expenditures (capex) in 2021 was maintenance capex.
- The Company paid dividends in accordance with its policy of maintaining the debt-to-capital ratio in line with the regulatory capital structure as approved by the PUB for rate-setting purposes.

2022 Summary/Outlook

- Newfoundland Power’s key credit metrics for the LTM ended June 30, 2022, continued to support the current rating category.
- Lower cash flow from operations for H1 2022, compared with the same period in 2021, reflects changes in the Company’s working capital and employee future benefits.
- The PUB approved a capital plan of $108.1 million for 2022, with approximately 51% of capex being part of electricity system maintenance.
- 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

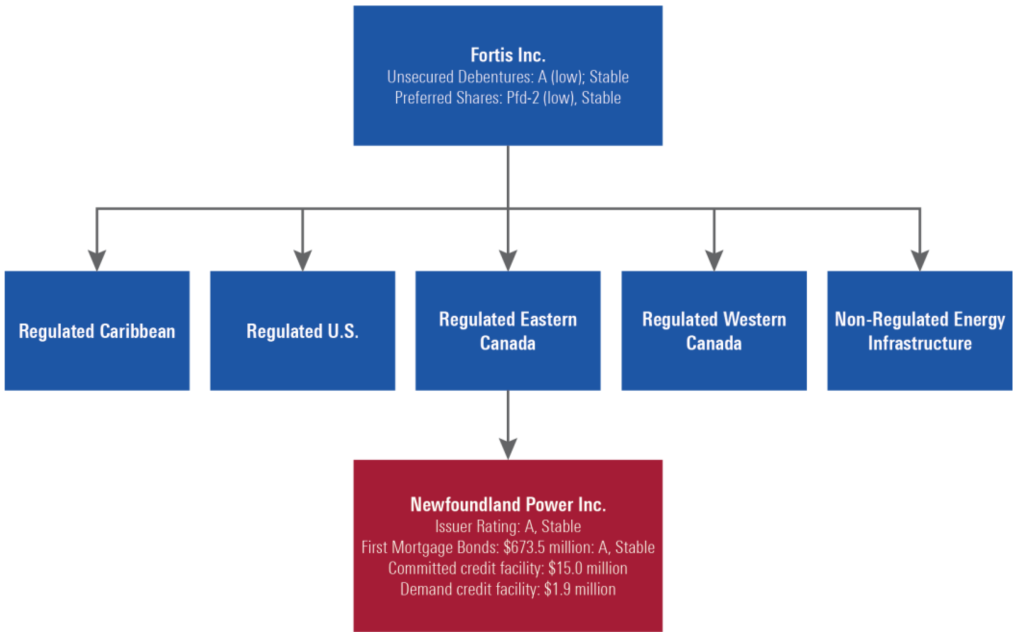
(CAD millions; as at June 30, 2022)	2022–23	2024–25	2026–27	Thereafter	Total
First mortgage sinking fund bonds	43.5	15.1	42.7	572.2	673.5
Credit facilities (unsecured)	15.0	0.0	0.0	0.0	15.0
Demand facility (uncommitted)	1.9	0.0	0.0	0.0	1.9
Total	**60.4**	**15.1**	**42.7**	**572.2**	**690.4**

- Newfoundland Power has a $100.0 million committed revolving unsecured credit facility, which was recently extended to a five-year term maturing August 2027 ($15.0 million outstanding as at June 30, 2022) and a $20.0 million uncommitted demand facility ($1.9 million outstanding as at June 30, 2022).
- 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, 2022.
- The debt repayment schedule is modest in the near term to the medium term.

Debt Outstanding (CAD millions)		Dec 2021
First-mortgage sinking fund bonds		
$40 million Series AF, due 2022	10.125%	28.4
$40 million Series AH, due 2026	8.900%	30.0
$50 million Series AI, due 2028	6.800%	38.5
$75 million Series AJ, due 2032	7.520%	60.8
$60 million Series AK, due 2035	5.441%	49.8
$70 million Series AL, due 2037	5.901%	59.5
$65 million Series AM, due 2039	6.606%	56.6
$70 million Series AN, due 2043	4.805%	64.4
$75 million Series AO, due 2045	4.446%	69.8
$75 million Series AP, due 2057	3.815%	71.3
$100 million Series AQ, due 2060	3.815%	98.0
		626.9
Credit & demand facilities		0.0
		626.9
Less: current portion		(35.2)
		591.7

- 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, 2022.

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 return on equity for rate-setting purposes. Rates are set based on a COS methodology.
- On November 22, 2021, the Company and intervenors reached a full Settlement Agreement with respect to the Company's 2022/2023 GRA. As a result of the 2022/2023 GRA, effective March 1, 2022, electricity rates decreased by 1.1% as a result of the order. The order resulted in minor changes in deferral accounts which were non material.
- Effective July 1, 2022, the PUB issued an order approving a 0.3% decrease in customer electricity rates. This was the result of a 6.4% decrease due to the annual operation of Hydro's Rate Stabilization Plan and Newfoundland Power's Rate Stabilization Account, offset by a 6.1% increase due to Hydro's Project Cost Recovery Rider. Hydro's Project Cost Recovery Rider was the beginning of the recovery from customers of the costs of the Muskrat Falls Project.
- In December 2021, the PUB approved Newfoundland Power's 2022 capital plan of $108.1 million.
- On June 29, 2022, the Company filed an application with the PUB requesting approval of its 2023 capital plan totaling $123.5 million. The application is currently under review by the PUB.

Regulator-Approved Accounts

Deferral accounts are used to smooth the impact of realized expenses and events differing from the 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 expenses 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.

ESG Checklist

* A **Relevant Effect** means that the impact of the applicable ESG risk factor has not changed the rating or rating trend on the issuer.
A **Significant Effect** means that the impact of the applicable ESG risk factor has changed the rating or trend on the issuer.
If any factor is proposed to have a Significant Effect, this should be reflected in the Press Release
** if Applicable is N, then Effect must be N; if Applicable is Y, then Effect must be R or S

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis:	Y/N**	Extent of the Effect on the ESG Factor on the Credit Analysis: None (N), Relevant (R) or Significant (S)*
Environmental		Overall:	N	N
	Emissions, Effluents, and Waste	Do we consider the costs or risks result, or could result in changes to an issuer's financial, operational, and/or reputational standing?	N	N
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs?	N	N
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?		
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?		
	Climate and Weather Risks	Will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact?	N	N
Social		Overall:	N	N
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?		
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?		
		Do violations of rights create a potential liability that could negatively affect the issuer's financial wellbeing or reputation?		
		Human Capital and Human Rights:		
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?		
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could result, in financial penalties or client attrition to the issuer?		
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?		
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?		
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N
Governance		Overall:	N	N
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N
		Are there any political risks that could impact the issuer's financial position or its reputation?	N	N
		Bribery, Corruption, and Political Risks:	N	N
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N
	Corporate / Transaction Governance	Does the issuer's corporate structure limit appropriate board and audit independence?	N	N
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N
		Corporate / Transaction Governance:	N	N
	Institutional Strength, Governance, and Transparency	Compared with other governments, do institutional arrangements provide a higher or lesser degree of accountability, transparency, and effectiveness?		
		Are regulatory and oversight bodies insufficiently protected from inappropriate political influence?		
		Are government officials insufficiently exposed to public scrutiny or held to insufficiently high ethical standards of conduct?		
		Institutional Strength, Governance, and Transparency:		
		Consolidated ESG Criteria Output:	N	N

Newfoundland Power Inc.							
(CAD millions)	June 30	Dec. 31	Dec. 31		June 30	Dec. 31	Dec. 31
Assets	**2022**	**2021**	**2020**	**Liabilities & Equity**	**2022**	**2021**	**2020**
Cash & equivalents	0	0	0	S.T. borrowings	2	15	7
Accounts receivable	65	73	66	Accounts payable	46	90	74
Regulatory assets	5	8	15	Current portion L.T.D.	8	35	7
Prepaid expenses & other	3	5	12	Other current liab.	36	29	21
Total current assets	**74**	**85**	**92**	**Total current liab.**	**92**	**170**	**109**
Net fixed assets	1,305	1,284	1,237	Long-term debt	663	589	624
Future income tax assets	238	288	331	Provisions	298	294	294
Intangibles	40	36	31	Deferred income taxes	184	184	175
Regulatory assets	55	0	0	Other L.T. liab.	16	1	1
Pensions & other	74	71	28	Preferred shares	0	0	0
				Common equity	532	526	516
Total assets	**1,785**	**1,764**	**1,720**	**Total liab. & SE**	**1,785**	**1,764**	**1,720**

	6 mos. June 30		12 mos. to June 30	For the year ended December 31				
Balance Sheet & Liquidity & Capital Ratios	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**	**2018**	**2017**
Current ratio	0.80	0.64	0.80	0.50	0.84	0.53	0.71	0.82
Total debt in capital structure (%)	55.8	54.9	55.8	54.8	55.3	54.1	54.5	54.6
Cash flow/total debt (%)	15.9	17.5	17.9	19.1	17.7	18.4	17.5	18.3
(Cash flow-dividends)/ capex (times)	0.67	0.87	0.68	0.76	0.67	0.82	0.80	0.77
Dividend payout ratio (%)	73.2	75.2	75.6	76.5	106.5	65.8	66.6	93.9
Coverage Ratios (times)								
EBIT gross interest coverage	2.30	2.46	2.59	2.67	2.60	2.54	2.58	2.72
EBITDA gross interest coverage	4.43	4.49	4.70	4.74	4.49	4.38	4.36	4.47
Fixed-charges coverage	2.30	2.46	2.59	2.67	2.56	2.49	2.53	2.66
Profitability Ratios								
EBITDA margin (%)	65.3	67.0	66.5	67.3	67.7	67.8	67.5	69.3
EBIT margin (%)	33.9	36.8	36.6	37.9	39.2	39.4	40.0	42.1
Profit margin (%)	16.1	15.8	17.5	17.4	17.4	17.9	17.6	17.9
Return on equity (%)	7.5	7.3	8.5	8.4	8.4	8.3	8.3	8.4
Return on capital (%)	5.5	5.5	5.9	5.9	6.0	6.0	6.0	6.1

Operating Statistics	For the year ended December 31					
Electricity Sales - Breakdown (GWh)	**2021**	**2020**	**2019**	**2018**	**2017**	**2016**
Residential	3,499	3,547	3,560	3,593	3,645	3,655
General service	2,216	2,182	2,287	2,283	2,277	2,295
Total sales	5,715	5,729	5,847	5,876	5,922	5,950
Growth in volume throughputs (%)	-0.2	-2.0	-0.5	-0.8	-0.5	-0.1
Customers						
Residential	236,796	235,260	234,132	233,104	231,639	229,815
Commercial	35,258	35,025	34,913	34,891	34,811	34,591
Total	272,054	270,285	269,045	267,995	266,450	264,406
Energy Generated and Purchased (GWh)						
Energy generated	435	439	431	435	437	427
Energy purchased	5,567	5,604	5,742	5,769	5,829	5,868
Energy generated + purchased	6,002	6,043	6,173	6,204	6,266	6,295
Less: transmission losses + internal use	287	314	327	328	343	345
Total sales	5,715	5,729	5,847	5,876	5,923	5,950
System losses and internal use (%)	5.0	5.5	5.6	5.6	5.8	5.8
Installed Generation Capacity (MW)						
Hydroelectric	97	97	97	97	97	97
Gas turbine	41	41	37	37	37	37
Diesel	5	5	5	5	5	5
Total	143	143	139	139	139	139
Native peak demand (MW)	1,251	1,356	1,458	1,362	1,446	1,381
Rate base (CAD millions)	1,203	1,182	1,154	1,117	1,092	1,061
Growth in rate base (%)	2	2	3	2	3	4

Rating History

	Current	2021	2020	2019	2018	2017
Issuer Rating	A	A	A	A	A	A
First Mortgage Bonds	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable	n/a	n/a	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, October 4, 2021.

Related Research

- "Corporate Risk Assessment Scorecard for the Utilities Industry," August 23, 2022.

Previous Report

- Newfoundland Power Inc.: Rating Report, October 19, 2021.

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.

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Newfoundland Power Inc.

Comparative Financial Forecasts
2025 - 2026
Statements of Income
($000s)

		2025		2026	
		Existing[1]	Proposed	Existing[1]	Proposed
1	Revenue from rates	751,315	768,770	750,723	789,602
2	Transfers from the RSA	52,520	45,819	45,409	41,537
3		803,835	814,589	796,132	831,139
4					
5	Purchased power expense	533,716	530,628	531,779	522,388
6	Demand management incentive account adjustments	-	-	-	-
7		533,716	530,628	531,779	522,388
8					
9	Contribution	270,119	283,961	264,353	308,751
10					
11	Other revenue[2]	11,019	9,224	11,646	6,861
12					
13	Other expenses:				
14	Operating expenses[3]	81,394	81,903	84,156	84,940
15	Employee future benefit costs[4]	8,122	8,122	1,812	1,812
16	Deferred cost recoveries and amortizations	492	(11,571)	492	9,888
17	Depreciation[5]	83,143	83,143	86,691	86,691
18	Finance charges[6]	42,240	41,075	43,427	41,089
19		215,391	202,672	216,578	224,420
20					
21	Income before income taxes	65,747	90,513	59,421	91,192
22	Income taxes[7]	20,037	27,466	18,010	27,541
23					
24	Earnings applicable to common shares[7]	45,710	63,047	41,411	63,651
25					
26	**Rate of Return and Credit Metrics**				
27	Rate of Return on Rate Base (%)	6.24	7.40	5.84	7.21
28	Regulated Return on Book Equity (%)	7.16	9.85	6.38	9.85
29	Interest Coverage (times)	2.2	2.8	2.0	2.8
30	CFO Pre-W/C + Interest / Interest (times)	2.9	3.4	2.8	3.7
31	CFO Pre-W/C / Debt (%)	9.6	13.2	9.0	14.1

[1] The 2025 and 2026 existing forecasts include the impact of the proposals in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

[2] Shown after reclassification for other contract costs and equity portion of AFUDC. Other revenue for proposed excludes interest on RSA.

[3] Shown after adjustment for non-regulated expenses and reclassification of other contract costs and current portion of employee future benefit costs.

[4] Shown after reclassification of current portion of employee future benefit costs.

[5] Shown after reclassification of tax on cost of removal.

[6] Shown after reclassification of equity portion of AFUDC.

[7] Shown after adjustment for non-regulated expenses and reclassification of tax on cost of removal.

Newfoundland Power Inc.

Comparative Financial Forecasts
2025 - 2026
Statements of Retained Earnings
($000s)

		2025		2026	
		Existing	Proposed	Existing	Proposed
1	Balance - Beginning	560,890	560,888	574,736	578,861
2	Net income for the period	43,229	60,566	38,827	61,067
3	Allocation of Part VI.1 tax	752	752	752	752
4		604,871	622,206	614,315	640,680
5					
6	Dividends				
7	Common shares	30,135	43,345	30,548	67,288
8					
9	Balance - End of Period	574,736	578,861	583,767	573,392

Newfoundland Power Inc.

Comparative Financial Forecasts
2025 - 2026
Balance Sheets
($000s)

	2025		2026	
	Existing	**Proposed**	**Existing**	**Proposed**
Assets				
Current Assets				
Accounts receivable	73,612	77,415	72,720	76,075
Materials and supplies	3,043	3,043	3,091	3,091
Prepaid expenses	3,928	3,928	3,990	3,990
Regulatory assets	58,628	14,030	61,196	13,955
	139,211	98,416	140,997	97,111
Property, plant and equipment	1,504,131	1,504,131	1,564,046	1,564,046
Intangible assets	66,020	66,020	66,506	66,506
Regulatory assets	342,197	310,829	343,563	300,331
Defined benefit pension plans	65,143	65,143	71,653	71,653
Other assets	1,484	1,484	1,474	1,474
	2,118,186	2,046,023	2,188,239	2,101,121
Liabilities and shareholder's equity				
Current Liabilities				
Accounts payable and accrued charges	97,946	96,976	97,748	96,000
Interest payable	8,176	8,176	9,304	9,304
Defined benefit pension plans	273	273	287	287
Other post-employment benefits	4,579	4,579	4,518	4,518
Current instalments of long-term debt	36,885	36,885	9,050	9,050
	147,859	146,889	120,907	119,159
Regulatory liabilities	243,992	243,992	259,648	259,646
Defined benefit pension plans	5,574	5,574	5,738	5,738
Other post-employment benefits	64,598	64,598	65,330	65,330
Other liabilities	1,526	1,526	1,508	1,508
Deferred income taxes	200,486	204,252	198,395	199,099
Long-term debt	809,094	730,010	882,625	806,928
Shareholder's equity				
Common shares	70,321	70,321	70,321	70,321
Retained earnings	574,736	578,861	583,767	573,392
	645,057	649,182	654,088	643,713
	2,118,186	2,046,023	2,188,239	2,101,121

Newfoundland Power Inc.

Comparative Financial Forecasts
2025 - 2026
Statements of Cash Flows
($000s)

		2025		2026	
		Existing	Proposed	Existing	Proposed
1	**Operating Activities**				
2	Net Earnings	43,229	60,566	38,827	61,067
3					
4	**Items Not Affecting Cash:**				
5	Depreciation of property, plant and equipment	84,988	84,988	88,568	88,568
6	Amortization of intangible assets and other	7,070	7,070	7,427	7,427
7	Change in long-term regulatory assets and liabilities	(47,556)	(48,411)	(46,530)	(30,667)
8	Deferred income taxes	(3,483)	284	(2,091)	(5,153)
9	Employee future benefits	(2,418)	(2,418)	(5,576)	(5,576)
10	Other	145	145	(11)	(11)
11		81,975	102,224	80,614	115,655
12					
13	Change in working capital	38,770	110,819	44,189	42,504
14		120,745	213,043	124,803	158,159
15					
16	**Investing Activities**				
17	Capital expenditures	(122,769)	(122,769)	(134,564)	(134,564)
18	Intangible asset expenditures	(9,353)	(9,353)	(7,695)	(7,695)
19	Contribution from customers and security deposits	2,500	2,500	2,500	2,500
20	Other	-	-	-	-
21		(129,622)	(129,622)	(139,759)	(139,759)
22					
23	**Financing Activities**				
24	Net proceeds (repayment) of committed credit facility	47,462	(31,626)	(16,511)	(13,127)
25	Proceeds from long-term debt	-	-	100,000	100,000
26	Repayment of long-term debt	(8,450)	(8,450)	(37,485)	(37,485)
27	Payment of debt financing costs	-	-	(500)	(500)
28	Dividends on Common shares	(30,135)	(43,345)	(30,548)	(67,288)
29		8,877	(83,421)	14,956	(18,400)
30					
31	**Change in Cash**	-	-	-	-
32	**Cash, Beginning of Year**	-	-	-	-
33	**Cash, End of Year**	-	-	-	-

Newfoundland Power Inc.

Comparative Financial Forecasts
2025 - 2026
Average Rate Base[1]
($000s)

	2025		2026	
	Existing	**Proposed**	**Existing**	**Proposed**
Plant Investment	1,381,842	1,381,842	1,425,802	1,425,802
Additions to Rate Base				
Defined Benefit Pension Costs	108,876	108,876	112,167	112,167
Deferred Credit Facility Costs	59	37	31	-
Cost Recovery Deferral - Hearing Costs	-	280	-	420
Cost Recovery Deferral - Conservation	22,010	22,010	22,242	22,242
Cost Recovery Deferral - 2024 Revenue Shortfall	4,706	4,235	4,706	2,823
Cost Recovery Deferral - 2025 Revenue Shortfall	-	4,693	-	7,040
Cost Recovery Deferral - Load Research and Retail Rate Design	800	800	902	902
Cost Recovery Deferral - Pension Capitalization	1,020	1,020	672	672
Customer Finance Programs	1,435	1,435	1,450	1,450
	138,906	143,386	142,170	147,716
Deductions from Rate Base				
Other Post-Employment Benefits	89,012	89,012	90,703	90,703
Customer Security Deposits	1,270	1,270	1,270	1,270
Accrued Pension Obligation	5,706	5,706	5,885	5,885
Accumulated Deferred Income Taxes	35,249	35,249	37,782	37,782
Excess Earnings Account	3,566	3,566	3,566	3,566
Refundable Investment Tax Credits	265	265	247	247
	135,068	135,068	139,453	139,453
Average Rate Base Before Allowances	1,385,680	1,390,160	1,428,519	1,434,065
Cash Working Capital Allowance	7,865	1,475	7,829	1,713
Materials and Supplies Allowance	14,164	15,181	14,389	15,422
Average Rate Base at Year End	1,407,709	1,406,816	1,450,737	1,451,200

[1] All amounts shown are averages.

Newfoundland Power Inc.

Comparative Financial Forecasts
2025 - 2026
Weighted Average Cost of Capital
($000s)

		2025		2026	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Average Capitalization**				
2	Debt	826,322	786,781	868,798	791,407
3	Common Equity	638,134	640,195	649,573	646,448
4		1,464,456	1,426,976	1,518,371	1,437,855
5					
6	**Average Capital Structure (%)**				
7	Debt	56.43	55.14	57.22	55.04
8	Common Equity	43.57	44.86	42.78	44.96
9		100.00	100.00	100.00	100.00
10					
11	**Cost of Capital (%)**				
12	Debt	5.10	5.21	4.99	5.18
13	Common Equity	7.16	9.85	6.38	9.85
14					
15					
16	**Weighted Average Cost of Capital (%)**				
17	Debt	2.88	2.87	2.86	2.85
18	Common Equity	3.12	4.42	2.73	4.43
19		6.00	7.29	5.59	7.28

Newfoundland Power Inc.

Comparative Financial Forecasts
2025 - 2026
Rate of Return on Rate Base
($000s)

		2025		2026	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Regulated Return on Equity	45,710	63,047	41,411	63,651
2					
3	Finance Charges				
4	Interest on Long-Term Debt	38,600	38,600	40,860	40,860
5	Other Interest	4,695	3,531	3,972	1,635
6	Amortization of Bond Issue Expenses	221	221	217	217
7	AFUDC	(1,350)	(1,350)	(1,696)	(1,696)
8		42,166	41,002	43,353	41,016
9					
10	Return on Rate Base	87,876	104,049	84,764	104,667
11					
12	Average Rate Base	1,407,709	1,406,816	1,450,737	1,451,200
13					
14	Rate of Return on Rate Base (%)	6.24	7.40	5.84	7.21

Newfoundland Power Inc.

Financial Performance
2025P - 2026P
Inputs and Assumptions

Energy Forecasts: Energy forecasts are based on economic indicators taken from the Conference Board of Canada Economic Forecast, dated August 2, 2023.

Revenue Forecast: The revenue forecast is based on the Customer, Energy and Demand forecast dated September 14, 2023.

Forecast revenue based on Existing Rates for 2025 through 2026 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 Weather Normalization reserve; and (iv) 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. 8 (2011), P.U. 13 (2013), P.U. 18 (2015), and P.U. 3 (2022). Forecast revenue for 2025 and 2026 also reflects recovery through the RSA of certain costs related to the implementation of the Electrification initiatives 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 September 14, 2023.

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 2025 and 2026 revenue requirement.

Employee Future Benefit Costs: Pension funding is based on the actuarial valuation dated as at December 31, 2022.

Pension discount rate is 4.80% for 2025 through 2026.

Expected return on pension plan assets is 5.75% for 2025 through 2026.

OPEBs discount rate is 5.30% for 2025 through 2026.

Cost Recovery Deferrals: The 2025 and 2026 forecasts include the deferred recovery over a 10-year period of certain Conservation program costs.

The 2025 and 2026 forecasts include the deferred recovery over a 10-year period of certain Electrification costs as reflected in the Application.

The 2025 and 2026 forecasts include the deferral of costs related to the Load Research Study and Retail Rate Design Review.

The 2025 and 2026 forecasts include the deferred recovery over a 30-month period of $1.0 million in external costs related to the *2025/2026 General Rate Application* beginning July 1, 2025.

The 2025 and 2026 forecasts include the amortization beginning July 1, 2025, of a $6.7 million revenue shortfall related to a July 1, 2024 rate implementation date proposed in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

The 2025 and 2026 forecasts include the amortization beginning July 1, 2025, of a $16.8 million revenue shortfall related to a July 1, 2025 rate implementation date for the *2025/2026 General Rate Application.*

The 2025 and 2026 forecasts include the deferral of $5.1 million in revenue related to forecast Excess Earnings in 2023.

Newfoundland Power Inc.

Financial Performance
2025P - 2026P
Inputs and Assumptions

Cost Recovery Deferrals (cont'd):	The 2025 and 2026 forecasts include the amortization over a 60-month period of $1.4 million in income tax impacts beginning on January 1, 2023 related to the change in pension capitalization approved in the *2022/2023 General Rate Application.* The 2025 and 2026 forecasts include the amortization over a 60-month period of $1.1 million in income tax impacts beginning on January 1, 2024 related to the change in pension capitalization approved in the *2022/2023 General Rate Application.*
Depreciation Rates:	Depreciation rates are based on the *2019 Depreciation Study.*
Operating Costs:	The operating forecast for 2025 and 2026 reflects the most recent management estimates. Operating forecasts for 2025 and 2026 reflect projected labour increases of 4.45% in 2025 and 4.50% in 2026, and non-labour increases based upon the GDP deflator.
Capital Expenditures:	Capital Expenditures for 2025 and 2026 are based on the *2024 Capital Budget Application* and the *2023 Supplemental Capital Expenditure Application.*
Short-Term Interest Rates:	Average short-term interest rates are forecast to be 4.75% for 2025 and 2026.
Long-Term Debt:	A $100.0 million long-term debt issue is forecast to be completed in March 2026. The debt is forecast for 30 years at a coupon rate of 5.50%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.
Dividends:	Common share 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 2025 and 2026.

Newfoundland Power Inc.

Forecast Average Rate Base[1]
2025 - 2026
($000s)

		2025	2026
1	Plant Investment	1,381,842	1,425,802
2			
3	Additions to Rate Base		
4	Defined Benefit Pension Costs	108,876	112,167
5	Deferred Credit Facility Costs	37	-
6	Cost Recovery Deferral - Hearing Costs	280	420
7	Cost Recovery Deferral - Conservation	22,010	22,242
8	Cost Recovery Deferral - 2024 Revenue Shortfall	4,235	2,823
9	Cost Recovery Deferral - 2025 Revenue Shortfall	4,693	7,040
10	Cost Recovery Deferral - Load Research and Rate Design	800	902
11	Cost Recovery Deferral - Pension Capitalization	1,020	672
12	Customer Finance Programs	1,435	1,450
13		143,386	147,716
14			
15	Deductions from Rate Base		
16	Other Post-Employment Benefits	89,012	90,703
17	Customer Security Deposits	1,270	1,270
18	Accrued Pension Obligation	5,706	5,885
19	Accumulated Deferred Income Taxes	35,249	37,782
20	Excess Earnings Account	3,566	3,566
21	Refundable Investment Tax Credits	265	247
22		135,068	139,453
23			
24	Average Rate Base Before Allowances	1,390,160	1,434,065
25			
26	Cash Working Capital Allowance	1,475	1,713
27			
28	Materials and Supplies Allowance	15,181	15,422
29			
30	Average Rate Base at Year End	1,406,816	1,451,200

[1] Based upon proposed rates. All amounts shown are averages.

Newfoundland Power Inc.

2025 Revenue Requirement[1]
($000s)

		Existing[2]	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	533,716	(3,088)	530,628
3	Operating Costs	81,394	509	81,903
4	Employee Future Benefit Costs	8,122	-	8,122
5	Deferred Cost Recoveries and Amortizations	492	(12,063)	(11,571)
6	Depreciation	83,143	-	83,143
7	Income Taxes	20,037	7,429	27,466
8		726,904	(7,213)	719,691
9				
10	**Return on Rate Base**	87,876	16,173	104,049
11				
12	**2025 Revenue Requirement**	814,780	8,960	823,740
13				
14	**Adjustments**			
15	Other Revenue[3]	(11,017)	1,794	(9,223)
16	Interest on Security Deposits	72	-	72
17	Energy Supply Cost Variance Adjustments	(42,073)	1,908	(40,165)
18	Other Transfers to RSA	(10,447)	4,793	(5,654)
19		(63,465)	8,495	(54,970)
20				
21	**2025 Revenue Requirement from Rates[4]**	751,315	17,455	768,770

[1] See *Volume 1, Application, Company Evidence and Exhibits, Section 4.3: 2025 and 2026 Revenue Requirements* for a summary of the Company's 2025 revenue requirement proposals.

[2] Existing revenue requirement includes the impact of the proposals in the Company's *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

[3] Excludes equity component of capitalized interest. Other revenue for proposed also excludes interest on the RSA.

[4] Existing revenue requirement for 2025 excludes price elasticity impacts related to revenue of $1,845,000. The required revenue increase of $19,300,000 in 2025 (see Exhibit 9, page 1 of 2, line 1, column E) is comprised of $17,455,000 and price elasticity impacts related to revenue of $1,845,000 (see Exhibit 9, page 1 of 2, line 1, column D).

Newfoundland Power Inc.

2026 Revenue Requirement[1]
($000s)

	Existing[2]	Changes	Proposed
Costs			
Power Supply Cost	531,779	(9,391)	522,388
Operating Costs	84,156	784	84,940
Employee Future Benefit Costs	1,812	-	1,812
Deferred Cost Recoveries and Amortizations	492	9,396	9,888
Depreciation	86,691	-	86,691
Income Taxes	18,010	9,531	27,541
	722,940	10,320	733,260
Return on Rate Base	84,764	19,903	104,667
2026 Revenue Requirement	807,704	30,223	837,927
Adjustments			
Other Revenue[3]	(11,644)	4,784	(6,860)
Interest on Security Deposits	72	-	72
Energy Supply Cost Variance Adjustments	(41,152)	5,657	(35,495)
Other Transfers to RSA	(4,257)	(1,785)	(6,042)
	(56,981)	8,656	(48,325)
2026 Revenue Requirement from Rates[4]	750,723	38,879	789,602

[1] See *Volume 1, Application, Company Evidence and Exhibits, Section 4.3: 2025 and 2026 Revenue Requirements* for a summary of the Company's 2026 revenue requirement proposals.

[2] Existing revenue requirement includes the impact of the proposals in the Company's *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

[3] Excludes equity component of capitalized interest. Other revenue for proposed also excludes interest on the RSA.

[4] Existing revenue requirement for 2026 excludes price elasticity impacts related to revenue of $5,586,000. The required revenue increase of $44,465,000 in 2026 (see Exhibit 9, page 2 of 2, line 1, column E) is comprised of $38,879,000 and price elasticity impacts related to revenue of $5,586,000 (see Exhibit 9, page 2 of 2, line 1, column D).

Newfoundland Power Inc.

2025 Return on Rate Base
($000s)

		Existing[1]	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	826,322	(39,541)	786,781
4	Common Equity	638,134	2,061 [2]	640,195
5		1,464,456	(37,480)	1,426,976
6				
7	**Average Capital Structure**			
8	Debt	56.43	(1.29)	55.14
9	Common Equity	43.57	1.29 [2]	44.86
10		100.00	0.00	100.00
11				
12	**Cost of Capital**			
13	Debt	5.10	0.11	5.21
14	Common Equity	7.16	2.69 [2]	9.85
15				
16	**Weighted Average Cost of Capital**			
17	Debt	2.88	(0.01)	2.87
18	Common Equity	3.12	1.30	4.42
19		6.00	1.29	7.29 [4]
20				
21	**Return on Rate Base[3]**			
22	Return on Debt	42,166	(1,164)	41,002
23	Return on Common Equity	45,710	17,337 [2]	63,047
24		87,876	16,173	104,049
25				
26	2025 Average Rate Base ($000s)			1,406,816 [5]
27				
28	**2025 Rate of Return on Rate Base**			**7.40%** [4]

[1] Includes the impact of the proposals in the Company's *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

[2] Reflects the Company's proposed return on common equity of 9.85% in 2025.

[3] Total financing costs for 2025 forecast are as follows ($000s):

Return on debt from above	41,002
Add: Interest on security deposits and other	73
Finance Charges, Exhibit 5, Page 1, Line 18	41,075

[4] Under the Asset Rate Base Method, differences between average invested capital and average rate base exist for the cash working capital allowance, the materials and supplies allowance and construction work in progress. For 2025, these differences result in the weighted average cost of capital of 7.29% differing by 0.11% from the rate of return on rate base of 7.40%.

[5] See Exhibit 6, line 30.

Newfoundland Power Inc.

2026 Return on Rate Base
($000s)

		Existing[1]	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	868,798	(77,391)	791,407
4	Common Equity	649,573	(3,125) [2]	646,448
5		1,518,371	(80,516)	1,437,855
6				
7	**Average Capital Structure**			
8	Debt	57.22	(2.18)	55.04
9	Common Equity	42.78	2.18 [2]	44.96
10		100.00	0.00	100.00
11				
12	**Cost of Capital**			
13	Debt	4.99	0.19	5.18
14	Common Equity	6.38	3.47 [2]	9.85
15				
16	**Weighted Average Cost of Capital**			
17	Debt	2.86	(0.01)	2.85
18	Common Equity	2.73	1.70	4.43
19		5.59	1.69	7.28 [4]
20				
21	**Return on Rate Base[3]**			
22	Return on Debt	43,353	(2,337)	41,016
23	Return on Common Equity	41,411	22,240 [2]	63,651
24		84,764	19,903	104,667
25				
26	2026 Average Rate Base ($000s)			1,451,200 [5]
27				
28	**2026 Rate of Return on Rate Base**			**7.21%** [4]

[1] Includes the impact of the proposals in the Company's *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023.

[2] Reflects the Company's return on common equity of 9.85% in 2026.

[3] Total financing costs for 2026 forecast are as follows ($000s):

Return on debt from above	41,016
Add: Interest on security deposits and other	73
Finance Charges, Exhibit 5, Page 1, Line 18	41,089

[4] Under the Asset Rate Base Method, differences between average invested capital and average rate base exist for the cash working capital allowance, the materials and supplies allowance and construction work in progress. For 2026, these differences result in the weighted average cost of capital of 7.28% differing by 0.07% from the rate of return on rate base of 7.21%.

[5] See Exhibit 6, line 30.

Newfoundland Power Inc.

2025 Revenue Requirement to Revenue from Rates Reconciliation
($000s)

		Existing A	Proposed B	Difference C	Price Elasticity[1] D	Proposed Increase[2] E
1	**Revenue From Rates**	751,315[3]	768,770[4]	17,455[5]	1,845	19,300
2						
3	**RSA Charges**[6]	71,191	71,002	(189)	189	-
4						
5	**MTA Charges**[6]	20,270	20,666	396	49	445
6						
7	**Total**	842,776	860,438	17,662	2,083	19,745

[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] Includes higher rate revenue in 2025 associated with the proposed July 1, 2024 rate change. See *Exhibit 7,* page 1 of 2.
[4] Revenue from proposed rates from *Exhibit 7,* page 1 of 2. Includes revenue from proposed rates in the *2025/2026 General Rate Application* with effect on July 1, 2025.
[5] *Exhibit 7* of the Application indicates a required increase in 2025 revenue from rates of $17,455,000.
[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2023.

Newfoundland Power Inc.

2026 Revenue Requirement to Revenue from Rates Reconciliation
($000s)

		Existing A	Proposed B	Difference C	Price Elasticity[1] D	Proposed Increase[2] E
1	**Revenue From Rates**	750,723[3]	789,602[4]	38,879[5]	5,585	44,464
2						
3	**RSA Charges**[6]	71,090	70,525	(565)	565	-
4						
5	**MTA Charges**[6]	20,250	21,191	941	151	1,092
6						
7	**Total**	842,063	881,318	39,255	6,301	45,556[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 Includes higher rate revenue in 2026 associated with the proposed July 1, 2024 rate change. See *Exhibit 7,* page 2 of 2.

4 Revenue from proposed rates from *Exhibit 7,* page 2 of 2. Includes revenue from proposed rates in the *2025/2026 General Rate Application* with effect on July 1, 2025.

5 *Exhibit 7* of the Application indicates a required increase in 2026 revenue from rates of $38,879,000.

6 The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2023.

7 See *Exhibit 10,* Column E.

Newfoundland Power Inc.

2026 Average Customer Billing Impacts
($000s)

Forecast Impacts by Rate Class Under Existing and Proposed Rates
(includes July 1, 2023 RSA and MTA)

	Category	Existing Rates	Adjustment Due to Price Elasticity	Adjusted Existing Rates	Proposed Rates	Difference	Rate Increase
1		(A)[1]	(B)[2]	(C)[3]	(D)[4]	(E)[5]	(F)[6]
2							
3	1.1 Domestic	524,670	(5,967)	518,703	547,056	28,353	5.5%
4	1.1S Domestic Seasonal	1,743	-	1,743	1,838	95	5.5%
5	Total Domestic	526,413	(5,967)	520,446	548,894	28,448	5.5%
6							
7	2.1 General Service 0-100 kW	111,305	(310)	110,995	117,051	6,056	5.5%
8	2.3 General Service 110-1000 kVA	129,157	-	129,157	136,104	6,947	5.4%
9	2.4 General Service over 1000 kVA	55,370	-	55,370	58,319	2,949	5.3%
10	Total General Service	295,832	(310)	295,522	311,474	15,952	5.4%
11							
12	4.1 Street and Area Lighting	16,842	-	16,842	17,837	995	5.9%
13	Forfeited Discounts	2,976	(24)	2,952	3,113	161	5.5%
14							
15	**Total**	842,063	(6,301)	835,762	881,318	45,556	5.5%

[1] Column A is the forecast revenue plus RSA and MTA effective July 1, 2023 under existing rates based on the 2026 test year sales forecast without elasticity impacts. Existing rates include higher rate revenue in 2026 associated with the proposed July 1, 2024 rate change. See *Exhibit 9,* page 2 of 2, Column A.

[2] Column B is the elasticity impact on existing customer billings reflecting a 5.5% average increase in customer rates.

[3] Column C is the forecast customer billings under existing rates adjusted for elasticity impacts (Column A + Column B).

[4] Column D is the forecast customer billings under proposed rates. 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[1] and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2024 Existing Rates	July 1, 2025 Proposed Rates
Domestic - Rate #1.1		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$16.06/month	$17.02/month
Exceeding 200 Amp Service	$21.06/month	$22.02/month
Energy Charge - All kilowatt-hours	13.449 ¢/kWh	14.178 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$16.06/month	$17.02/month
Exceeding 200 Amp Service	$21.06/month	$22.02/month
Prompt Payment Discount	1.5%	1.5%
Domestic - Rate #1.1S		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$16.06/month	$17.02/month
Exceeding 200 Amp Service	$21.06/month	$22.02/month
Energy Charge		
Winter Seasonal	14.402 ¢/kWh	15.131 ¢/kWh
Non-Winter Seasonal	12.152 ¢/kWh	12.881 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$16.06/month	$17.02/month
Exceeding 200 Amp Service	$21.06/month	$22.02/month
Prompt Payment Discount	1.5%	1.5%

[1] Reflects the customer rates proposed in the *2024 Rate of Return on Rate Base Application* filed with the Board on November 23, 2023, with effect on July 1, 2024.

Newfoundland Power Inc.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2024 Existing Rates	July 1, 2025 Proposed Rates
G.S. 0-100 kW (110 kVA) - Rate #2.1		
Basic Customer Charge		
Unmetered	$12.25/month	$13.59/month
Single Phase	$20.25/month	$21.59/month
Three Phase	$32.25/month	$33.59/month
Demand Charge Regular	$9.84/kW - winter $7.34kW - other	$10.33/kW - winter $7.83/kW - other
Energy Charge		
First 3,500 kilowatt-hours	13.308 ¢/kWh	14.030 ¢/kWh
All excess kilowatt-hours	10.304 ¢/kWh	10.847 ¢/kWh
Maximum Monthly Charge	22.226 ¢/kWh + B.C.C.	23.479 ¢/kWh + B.C.C.
Minimum Monthly Charge		
Unmetered	$12.25/month	$13.59/month
Single Phase	$20.25/month	$21.59/month
Three Phase	$32.25/month	$33.59/month
Prompt Payment Discount	1.5%	1.5%
G.S. 110-1000 kVA - Rate #2.3		
Basic Customer Charge	$49.64/month	$52.60/month
Demand Charge	$8.25/kVA-winter $5.75/kVA-other	$8.65/kVA-winter $6.15/kVA-other
Energy Charge		
First 150 kWh per kVA of demand (max. 50,000)	11.507 ¢/kWh	12.121 ¢/kWh
All Excess kWh	9.518 ¢/kWh	10.011 ¢/kWh
Maximum Monthly Charge	22.226 ¢/kWh + B.C.C.	23.479 ¢/kWh + B.C.C.
Minimum Monthly Charge	$49.64/month	$52.60/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)

	July 1, 2024 Existing Rates	July 1, 2025 Proposed Rates
G.S. 1000 kVA and Over - Rate #2.4		
Basic Customer Charge	$86.50/month	$91.66/month
Demand Charge	$7.91/kVA-winter $5.41/kVA-other	$8.27/kVA-winter $5.77/kVA-other
Energy Charge		
First 75,000 kWh	11.139 ¢/kWh	11.730 ¢/kWh
All Excess kWh	9.436 ¢/kWh	9.925 ¢/kWh
Maximum Monthly Charge	22.226 ¢/kWh + B.C.C.	23.479 ¢/kWh + B.C.C.
Minimum Monthly Charge	$86.50./month	$91.66/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

		July 1, 2024 Existing Rates	July 1, 2025 Proposed Rates
Fixtures			
Sentinel/Standard			
High Pressure Sodium	100W	$18.70	$19.79
	150W	23.46	24.82
	250W	33.63	35.57
	400W	47.37	50.07
Light Emitting Diode	LED 100	$16.34	$17.11
	LED 150	18.49	20.38
	LED 250	22.45	25.05
	LED 400	26.03	29.84
Post Top			
High Pressure Sodium	100W	$19.91	$21.07
Poles			
Wood		$6.22	$6.79
30' Concrete or Metal, direct buried		8.68	9.27
45' Concrete or Metal, direct buried		14.37	15.37
25' Concrete or Metal, Post Top, direct buried		6.16	6.47
Underground Wiring (per run)			
All sizes and types of fixtures		$14.64	$15.44

Schedule of Rules and Regulations

NEWFOUNDLAND POWER INC.

RULES AND REGULATIONS

1. INTERPRETATION:

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

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

(b) Unless the context requires otherwise these Rates, Rules and Regulations shall be interpreted such that <> words imparting the singular include the plural and vice versa.

2. CLASSES OF SERVICE:

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

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

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

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

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

3. APPLICATION FOR SERVICE:

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

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

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

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

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

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

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

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

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

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

RULES AND REGULATIONS

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 their expense and within a reasonable period of time, the equipment necessary to eliminate or prevent such interference.

NEWFOUNDLAND POWER INC.

RULES AND REGULATIONS

(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 their 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 their property and equipment from any disturbance beyond the reasonable control of the Company.

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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, their bill for such Service has been in arrears for more than 30 days.

7. METERING:

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

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

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

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

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

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

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

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

(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 the Customer's 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.

(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.

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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 their own transformation and all other facilities beyond the designated point of supply the monthly demand charge shall, subject to the minimum monthly charge, be reduced as follows:

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

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

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

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

10. BILLING:

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

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

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

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

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

(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.

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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.

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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.

Proposed Changes to the Rate Stabilization Clause

It is proposed that the Rate Stabilization Clause be amended to include Clause II.9 as follows:

9 On March 31st of each year, beginning in 2025, 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.

Newfoundland Power Inc.

Proposed Changes to the Demand Management Incentive Account Definition

It is proposed that the current definition for the Demand Management Incentive Account be replaced with the following effective January 1, 2025:

Demand Management Incentive Account Long Term - 23257
Current - 24230

This account shall be charged or credited with the amount by which the Demand Supply Cost Variance exceeds the Demand Management Incentive. The Demand Management Incentive equals ± $500,000 of test year wholesale demand charges.

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

$$(A – B) \times C$$

Where:

A = actual demand supply cost in dollars per kWh determined by dividing the wholesale demand charges in the calendar year by the weather normalized kWh purchases for that year (as will be reported in Return 15 of Newfoundland Power's Annual Report to the Board).

B = test year demand supply cost in dollars per kWh determined by dividing the test year wholesale demand charges by the test year kWh purchases.

C = the weather normalized annual purchases in kWh.

The amount charged or credited to this account shall be adjusted for applicable income taxes calculated at the statutory income tax rate.

Disposition of Any Balance in this Account

Newfoundland Power shall file an Application with the Board no later than the 1st day of March each year for the disposition of any balance in this account.

Newfoundland Power Inc.

Proposed Changes to the Pension Capitalization Cost Deferral Account Definition

It is proposed that the current definition for the Pension Capitalization Cost Deferral Account be replaced effective January 1, 2025, with the following:

Pension Capitalization Cost Deferral Account 185xx

This account shall be charged with amounts equal to cost impacts resulting from the change in capitalizing pension costs from the indirect method via general expenses capitalized to the direct method via a labour loader, effective January 1, 2023 and ending December 31, 2024.

Charges to the account will be amortized over a 5-year period commencing January 1, 2023.

Transfers to, and from, the account will be tax-effected.