Board of Commissioners of Public Utilities

Newfoundland Power Inc. - 2025/2026 General Rate Application

Report date: April 24, 2024

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1. Executive summary

1.1. Project overview

Grant Thornton LLP (“we”, “us”, “our” or “Grant Thornton”) has been engaged by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the “Board”) to review the Newfoundland Power Inc. (the “Company” or “Newfoundland Power”) 2025/2026 General Rate Application (the “2025/2026 GRA” or the “Application”) as filed by Newfoundland Power Inc., dated December 12, 2023. This report is provided for the Board's use in evaluating the Application submitted by the Company.

1.2. Scope of work

Our report outlines the results of our procedures to review the Application and document our findings and observations. Specifically, we have undertaken the following procedures:

- Reviewed the methodology and assumptions used by the Company for estimating expenses and return;
- Reviewed the Company’s calculation of estimated average rate base for forecast years;
- Reviewed the proposed rates necessary to meet the estimated revenue requirements in forecast years;
- Reviewed proposed regulatory mechanisms and accounts;
- Detailed analysis, enquiries, reperformance of calculations and other analytical procedures with respect to financial information in the Company’s Application, including assessing the reasonableness of explanations and compliance with Board orders; and
- Prepared a report on our findings.

Specific procedures are outlined in each section of this report to reflect the nature of the specific matter reviewed and the nature of the information filed by the Company. However, in general our procedures were comprised of:

- Enquiry and analytical procedures with respect to financial information in the Company’s 2025/2026 GRA;
- Assessing the reasonableness of the Company’s explanations; and
- Assessing the Company’s compliance with associated Board Orders.

All tables in our report reflect the balances stated in the information filed by the Company and may contain rounding differences due to presentation.

1.3. Restrictions and limitations

Our scope of work is as set out throughout this report. The procedures undertaken in the course of our review do not constitute an audit of the Company’s financial information and consequently, we do not express an audit opinion on the financial information provided by the Company. Our opinions on other matters are outlined throughout this report.

We acknowledge that our report will be communicated to the parties to the matter and may become a public document accessible through the Board’s website. We have given the Board our consent to use our report for this purpose. Our report is not to be reproduced or used for any purpose other than that outlined above without prior written permission in each specific instance. Grant Thornton LLP recognizes no responsibility to any third party who may rely on this report or other material provided to the Board.

Unless stated otherwise in this report, Grant Thornton LLP has relied on information provided by the Company, the Board's website and third-party sources in preparing this report, whom Grant Thornton LLP believes is reliable. We are not guarantors of the information upon which we have relied in preparing the report and, except as stated, we have not audited or otherwise attempted to verify any of the underlying information or data contained in this report. We have made efforts to ensure a conservative, realistic and transparent approach, however, some of the analysis depends on the input from third parties whose opinions may influence the conclusions. All analysis, information and recommendations contained herein are based on the information available to Grant Thornton LLP as of this report's date.

1.4. Summary of findings, observations and conclusions

The following represents a summary of our key findings and recommendations based on the procedures outlined throughout the report:

Figure 1 – Summary of findings, observations and conclusions

#	Report section	Findings, observations, and conclusions
2.	**Forecasting methodology and assumptions**	**System of accounts** – We have determined the Company is following the system of accounts prescribed by the Board. The system of accounts is comprehensive and well-structured and provides adequate flexibility for reporting purposes. **Forecast methodology** – We have determined that the overall forecast methodology used by the Company is consistent with the 2022/2023 GRA. The underlying assumptions have been reviewed based on supporting evidence provided by the Company and we have found no exceptions.
3.	**Revenue requirement**	In our review, we have addressed the major components of revenue requirement, except for the return on equity, and our specific comments on each are outlined in the various individual sections of this report. For clarity, while we have commented on the calculated rate of return on rate base, the appropriateness of the return on common equity is beyond the scope of our report. The effect of all the factors noted in Newfoundland Power's Application reflect an increase in revenue requirement from rates of $19,300,000 in 2025 and $44,464,000 in 2026, which the Company is proposing to obtain by increasing rates effective July 1, 2025 by an average of 5.5%. Please note that this assumes that the 1.5% customer rate increase as proposed in the Company's 2024 Rate of Return on Rate Base Application is approved.

#	Report section	Findings, observations, and conclusions
4.	**Power supply, operating and employee future benefit costs.**	**Power supply costs –** Based upon our analysis, purchased power forecast for 2025/2026 proposed appears consistent with billing rates from Newfoundland and Labrador Hydro ("NL Hydro" or "Hydro") using the effective October 1, 2019 and forecast increase in energy sales. We also noted that the Company has not rebased its forecast power supply energy costs into base rates for 2025 and 2026 revenue requirements, which is not consistent past practice. **Operating costs –** Based upon our initial trend analysis and review, we have not yet concluded on the 2024, 2025 and 2026 forecast operating expenses. There are some matters we have identified that require additional analysis. These matters include: 1) total labour; 2) vehicle expenses; 3) plants, substations, system operations and buildings; 4) insurance; 5) other company fees; 6) vegetation management; and 7) computing equipment and software. Our comments in this report reflect our observations and recommendations as of the date of this report. We will provide any further observations and recommendations in a supplemental report to the Board. **Executive compensation** – We reviewed the methodology and supporting documentation for executive compensation and the resulting amounts included in forecast years for any unusual trends. Based on this review, the calculation of forecasted executive compensation for 2025 and 2026 is consistent with past practice. **Salaries and benefits -** Based upon our initial review, we have not yet concluded on employee salaries and benefits. We will make our comments in a supplemental report to the Board. **Employee future benefits** – Based on our review of employee future benefits, nothing has come to our attention that would suggest forecasted employee future benefits for 2025 and 2026 are unreasonable. **Finance charges** – Based upon our analysis, nothing has come to our attention to indicate that the proposed finance charges for 2025 and 2026 are unreasonable. **Intercompany charges** – Based upon our analysis, intercompany charges are calculated using a methodology that is consistent year over year. As a result of our review, nothing has come to our attention that would lead us to believe that forecast intercompany charges are unreasonable. **Non-regulated expenses** – Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, are unreasonable or not in accordance with Board Orders. However, the proposed changes to STI measures, specifically the addition of the regulatory performance component as a STI measure and the regulatory expense inclusion rate for STI payments resulting from this metric have not yet been approved by the Board.

#	Report section	Findings, observations, and conclusions
5.	**Deferred cost recoveries and amortization**	**Regulatory deferrals -** Based on our review and analysis, nothing has come to our attention to indicate the regulatory deferrals and amortizations included in the Application are unreasonable or not in accordance with relevant Board Orders. **Conservation and demand management ("CDM") cost deferrals** – Based upon our review of the Company's CDM Cost Deferral Account, we have noted no errors in the deferrals and forecast amortization based on an amortization period of ten years approved by the Board. **Electrification cost deferrals** – Based upon our review of the Company's Electrification Cost Deferral Account, we have noted no issues and conclude that the proposal to recover approved customer electrification costs through its Rate Stabilization Account ("RSA") over 10 years appears reasonable.
6.	**Depreciation**	Based on our review, we conclude that the depreciation rates used to calculate the proposed forecast for 2025 and 2026 agree to those recommended in the Gannet Fleming 2019 Depreciation Study ("2019 Depreciation Study") and the Company's pre-filed evidence. We have recalculated the depreciation expense for 2025 and 2026 without identifying any material errors and conclude that the depreciation expense is calculated in accordance with the rates prescribed in the 2019 Depreciation Study.
7.	**Income taxes**	Based upon our analysis, income tax expense for forecast 2024 and proposed 2025 and 2026 appear consistent with substantively enacted corporate income tax rates and forecast increases in net income.

<table>
<tr><th>#</th><th>Report section</th><th>Findings, observations, and conclusions</th></tr>
<tr><td>8.</td><td>Return on rate base</td><td>We have completed our review of the return on rate base included in the Company’s proposed revenue requirement for 2025 and 2026 and can offer the following comments:
We reviewed the underlying support of the reconciling items between the average rate base and the average invested capital amounts and found no discrepancies. Based upon the identified procedures and our review of the Company’s response, we did not note any discrepancies in the clerical accuracy of the proposed 2025 and 2026 return on average rate base calculation. The proposed average rate base accurately reflects the Company’s proposals with respect to the regulatory deferral accounts and the updated calculations related to the rate base allowances.
We have found no exceptions or errors in the proposed capital structure. The proposed capital structure for 2025 and 2026 is consistent with the position confirmed by the Board in Order No. P.U. 3 (2022). The calculations of capital structure are consistent with Exhibit 3 (Page 6 of 9), Exhibit 5 (Page 6 of 9) and Exhibit 8 presented in the 2025/2026 GRA. It is consistent with prior practice and in accordance with the underlying expert report filed by the Company.
We have reviewed how the Company has incorporated the proposed return on equity into the calculation of return on rate base and found no errors. Please note that the 2025 and 2026 proposed rate of return on equity is outside of the scope of this report.
During our review we noted that the WACC and the rate of RORB did not agree. While we have discussed this matter with the Company, we have not fully completed our assessment of this issue prior to the report date. Our work is ongoing and any additional observations or recommendations will be communicated to the Board via a Supplemental Report.</td></tr>
<tr><td>9.</td><td>Proposed forecast revenue</td><td>Based on our procedures nothing has come to our attention to indicate the forecast revenue from rates for 2023, 2024, 2025 and 2026 are unreasonable.</td></tr>
<tr><td>10.</td><td>Other adjustments</td><td>Other revenue – Based on our procedures nothing has come to our attention to indicate the forecast other revenues for 2023, 2024, 2025 and 2026 appear unreasonable.
Energy supply cost variance adjustments –Based on the Company’s proposal to not rebase power supply energy costs, we recalculated the 2025 and 2026 proposed energy supply cost variance adjustments and found no errors.
Other transfers to RSA – Based on our review and analysis, nothing has come to our attention to indicate that other transfers to the RSA are unreasonable.</td></tr>
</table>

#	Report section	Findings, observations, and conclusions
11.	**Proposed revenue from rates**	Based on our procedures, we find that the revenue requirement proposed by the Company is calculated based upon the revised Schedule of Rates, Tolls and Charges effective July 1, 2025, and the factors proposed in this Application.
12.	**Demand management incentive ("DMI")**	Based upon our review and analysis, nothing has come to our attention to indicate that the proposal to amend the definition of the DMI account definition to establish a threshold of ± $500,000 is unreasonable.

2. Chart of accounts, forecasting methodology and assumptions

According to Newfoundland Power, their forecast of revenue and expenses for 2024, 2025 and 2026 is based on the expected operating and capital requirements, as well as assumptions, which reflect the best estimate of future economic conditions and events.

2.1. Procedures

Our approach to the review of this matter focused on the following main objectives:

- Reviewed the Company's code of accounts and considered any material changes;
- Reviewed the Company's minutes from meetings to consider any key events that may impact the 2025/2026 GRA;
- Assessed the methodology used by the Company for forecasting revenues and expenses;
- Assessed the major assumptions disclosed in Exhibits 3 and 5 of the Application for consistency with forecast information reflected throughout the Application; and,
- Assessed the incorporation of assumptions into the forecast presented by management.

2.2. System of accounts

Section 58 of the Public Utilities Act permits the Board to prescribe the form of accounts to be maintained by the Company. Our review of the Company's accounting system and code of accounts is to ensure it can provide information sufficient to meet the Board's reporting requirements. We have observed that the Company has in place a well-structured, comprehensive system of accounts and reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements.
On March 28, 2024, the Company filed a summary of revisions to its system of accounts with the Board, along with a copy of the revised System of Accounts as part of the Company's 2023 Annual Report. The Company indicated that the revisions principally relate to updating definitions and minor wording changes to improve clarity and accuracy of account descriptions. There was also the addition of two new accounts, first relating to Pension Capitalization Cost Deferral Accounts, and the second relating to the Payroll Overhead Suspense and Recovery Accounts to capture transactions related to the recording of pension capitalization through a labour loader. The Company has noted that accounts for Pension Capitalization Cost Deferral and Load Research and Rate Design Cost Deferral were added to the System of Accounts in the 2023 Annual Report to the Board. Aside from these revisions, there are no material changes to the Company's System of Accounts.

2.3. Forecast methodology

The Company has indicated that the 2025 and 2026 forecasts were developed by Newfoundland Power's Finance Department based on a number of economic and financial inputs. The primary input is Customer, Energy and Demand ("CED") Forecast prepared as of September 2023. The CED forecast is used to forecast revenue and purchased power expense and develop the Company's capital budgets. For capital budgeting purposes, the CED forecast is used to support budget estimates for customer-driven projects and is used as the basis for peak load forecasts used to determine when equipment will exceed design parameters. The economic assumptions used in preparing the customer and energy sales forecast are based on the Conference Board of Canada's Provincial Medium-Term Economic Forecast, dated August 2nd, 2023. The Conference Board of Canada is the Company's primary provider of economic information for development of the CED forecast. A description of all other major components and the key assumptions used in the preparation of the 2025 and 2026 forecasts are provided in the Application (Vol 1) on pages 8 and 9 in Exhibits 3 and 5 to Newfoundland Power's GRA evidence.

Additionally, the Company has noted that they provide electrical service to three distinct categories of customers. These are Domestic, General Service and Street and Area Lighting customers. Forecasting energy sales for each of these categories of customers is completed separately. The Conference Board of Canada forecast of Newfoundland and Labrador's household disposable income is an independent variable used in the average use regression model for Domestic customers' energy consumption. The Conference Board of Canada forecast of Newfoundland and Labrador's Service Sector Gross Domestic Product ("GDP") is used in the average use regression model for small General Service customers' energy consumption. The forecast of energy sales for large General Service Customers is completed on an individual basis. The forecast of energy sales relating to Street and Area Lighting customers is based on the types and quantities of fixtures forecast to be in service over the forecast period.

2.4. Assessment of inputs, assumptions and incorporation into forecast

The following summarizes the list of inputs and assumptions included in Exhibit 5 and refers to the section of this report which outlines the results of our review:

Figure 2 – Summary of forecast inputs and assumptions

Exhibit 5 - inputs and assumptions	Input or assumption	Conclusion
Energy forecast	The economic assumptions used in preparing the customer and energy sales forecast are based on the Conference Board of Canada's ("CBOC") Provincial Medium-Term Forecast, dated August 2nd, 2023.	Applying the CBOC inputs is consistent with the 2022/2023 General Rate Application (the "prior GRA" or "2022/2023 GRA"). We compared the model inputs to the CBOC report and found no exceptions.
Revenue forecast	Customer, Energy and Demand Forecast dated September 14, 2023.	Consistent with the prior GRA, revenue forecast is derived from the CED. We compared the revenue forecast to the CED forecast and found no exceptions.
Purchased power expense	Customer, Energy and Demand Forecast dated September 14, 2023 and NL Hydro's approved rates effective October 1, 2019.	Consistent with the prior GRA, purchased power expense is derived from the CED and NL Hydro's approved rates. We compared the purchase power expense assumptions to the NL Hydro approved rates and found no exceptions. We understand that the wholesale rate will be re-designed as

Exhibit 5 - inputs and assumptions	Input or assumption	Conclusion
		part of NL Hydro's next general rate application. However, the Company has indicated that the NL Hydro rate application is expected to be filed in 2025. Newfoundland Power has not rebased its forecast power supply energy costs into base rates for 2025 and 2026 revenue requirements.
Employee future benefit costs	Actuarially determined factors and valuation.	See **Employee Future Benefit Costs**
Cost recovery deferrals	Varies by mechanism.	See **Deferred cost recoveries and amortizations**
Depreciation rates	Based on 2019 Depreciation Study.	See **Depreciation**.
Operating costs	2025 and 2026 reflects recent management estimates. 2025 and 2026 reflect projected labour increases of 4.45% and 4.50%, respectively, and non-labour increases based upon the GDP deflator.	See **Operating Expenses**
Capital expenditures	2024 Capital Budget Application and the 2023 Supplemental Capital Expenditure Application.	We agreed the forecasted capital expenditures to the 2024 Capital Budget Application, which was not approved at the time of the 2025/2026 GRA filing, and have found no exceptions.
Short-term interest rates	The average short-term interest rates are forecast to be 4.75% for 2025 and 2026.	See **Finance Charges** – approach is consistent with the underlying short-term interest rate forecast provided by the Company.
Long-term debt	$100 million debt issuance in 2026, forecasted to have a coupon rate of 5.50% over 30 years. Normal sinking fund provisions for existing debt.	See **Finance Charges** – approach is consistent with the underlying long-term interest rate forecast provided by the Company.
Dividends	Forecasted based on maintaining a target common equity of 45%.	Consistent with the 2022/2023 GRA.
Income tax	Income tax rate of 30% for 2025 through 2026.	Consistent with the currently enacted corporate tax rates.

2.5. Conclusion

We have determined the Company is following the system of accounts prescribed by the Board. The system of accounts is comprehensive and well-structured and provides adequate flexibility for reporting purposes.

We have determined that the overall forecast methodology used by the Company is consistent with the 2022/2023 GRA. The underlying assumptions have been reviewed based on supporting evidence provided by the Company and we have found no exceptions.

3. Revenue requirement

3.1. Background

Revenue requirement reflects the amount of revenue the Company must collect in a given year in order to cover the costs of providing service to its customers, inclusive of a fair return for the Company's shareholders. Revenue requirement can be broken down into a number of cost categories. These categories are as follows:[1]

- Power supply costs;
- Operating costs;
- Employee future benefit costs;
- Deferred cost recoveries and amortizations;
- Depreciation;
- Income taxes;
- Return on rate base;
- Other revenue;
- Interest on security deposits;
- Energy supply cost variance adjustments; and
- Other transfers to RSA.

3.2. Procedures

Our procedures with respect to the Company's revenue requirement calculations were focused on the assessment of the reasonableness and accuracy of the calculation, the reasonableness of the underlying assumptions including the support for those assumptions, and the internal consistency between financial schedules included in the 2025/2026 GRA filing. In particular, the procedures we performed included the following:

- Recalculated revenue requirement to determine the mathematical accuracy of the financial schedules;
- Reviewed the Company's forecast methodology for components of the revenue requirement calculation; and
- Reviewed the 2025/2026 GRA for internal consistency.

3.3. Review of forecast revenue requirement

Revenue requirement cost categories from 2023 test year to 2026 proposed, and the corresponding sections of our report that address these categories, are outlined in the following table.

[1] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023, Exhibit 7

Figure 3 – Revenue requirement

Revenue requirement from rates					
(000s)	2023 Test Year	2024 Revised	2025P	2026P	Grant Thornton report section
Costs	*[1]*	*[2]*	*[3]*	*[4]*	
Power supply costs	459,924	459,924	530,628	522,388	Section 4
Operating costs	70,725	70,725	81,903	84,940	Section 4
Employee future benefit costs	2,771	2,771	8,122	1,812	Section 4
Deferred cost recoveries and amortization	(816)	(816)	(11,571)	9,888	Section 5
Depreciation	74,458	74,458	83,143	86,691	Section 6
Income taxes	20,944	21,928	27,466	27,541	Section 7
Subtotal	**628,006**	**628,990**	**719,691**	**733,260**	
Return on rate base	**82,275**	**93,126**	**104,049**	**104,667**	Section 8
Revenue requirement	**710,281**	**722,116**	**823,740**	**837,927**	
Annual change		*11,835*	*101,624*	*14,187*	
% change		*1.67%*	*14.07%*	*1.72%*	
Adjustments					
Other revenue	(6,473)	(6,473)	(9,223)	(6,860)	Section 10
Interest on security deposits	18	18	72	72	Section 4
Energy supply cost variance adjustments	-	-	(40,165)	(35,495)	Section 10
Other transfers to RSA	(4,581)	(4,581)	(5,654)	(6,042)	Section 10
	(11,036)	**(11,036)**	**(54,970)**	**(48,325)**	
Revenue requirement from rates	**699,245**	**711,080**	**768,770**	**789,602**	Sections 9 & 11
Year over year change ($)		*11,835*	*57,690*	*20,832*	
Year over year change (%)		*1.69%*	*8.11%*	*2.71%*	

[1] From Exhibit 7 (1st Revision): 2022 and 2023 Revenue Requirements filed with the Board on December 7, 2021, regarding the Company's 2022/2023 General Rate Application (Amended).
[2] Retrieved from Appendix C of the 2024 Rate of Return on Rate Base Application. The 2024 revenue requirement is the 2023 test tear requirement revised for the proposed increased return on rate base for 2024. We understand this Application is currently before the Board and therefore final figures are subject to change based on the Board order.
[3] Exhibit 7, pg.1 – 2025/2026 GRA
[4] Exhibit 7, pg.2 – 2025/2026 GRA

Based on the evidence included in Exhibit 9 of the Company's pre-filed evidence, Newfoundland Power has indicated it requires an increase in revenue requirement from rates of approximately $19.30 million in 2025 and $44.46 million in 2026. These requirements are based on the proposals that the Company has put forward relating to regulatory deferrals, a rate of return on average rate base of 7.40% in 2025 and 7.21% in 2026 and a rate of return on common equity of 9.85% in 2025 and 2026. The factors contributing to the increase are summarized on the following pages.

Figure 4 – Components of 2025 proposed rate change[2]

Components of 2025 proposed rate change				
(000s)	Existing (including elasticity adjustment)	Changes	Proposed	Rate Change %
Return on rate base	**$ 87,876**	**$ 16,173**	**$ 104,049**	1.90%
Other Costs				
Power supply costs	533,716	(3,088)	530,628	-0.40%
Operating costs	81,394	509	81,903	0.06%
Employee future benefit costs	8,122	-	8,122	-
Deferred cost recoveries and amortization	492	(12,063)	(11,571)	-1.40%
Depreciation	83,143	-	83,143	-
Income taxes	20,037	7,429	27,466	0.90%
Subtotal	**726,904**	**(7,213)**	**719,691**	
Total costs and return	**814,780**	**8,960**	**823,740**	
Adjustments				
Other revenue	(11,017)	1,794	(9,223)	0.20%
Interest on security deposits	72	-	72	-
Energy supply cost variance adjustments	(42,073)	1,908	(40,165)	0.20%
Other transfers to RSA	(10,447)	4,793	(5,654)	0.60%
Subtotal	(63,465)	8,495	(54,970)	
Elasticity adjustment	(1,845)	1,845	-	0.20%
2025 Revenue requirement from rates	**749,470**	**19,300**	**768,770**	2.30%
RSA	71,191	(189)	71,002	0.00%
MTA	20,270	396	20,666	0.05%
Elasticity adjustment	(238)	238	-	0.03%
Billed to customers	**$ 840,693**	**$ 19,745**	**$ 860,438**	**2.30%**

[2] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023, Exhibit 7 and Exhibit 9

Figure 5 – Components of 2026 proposed rate change[3]

Components of 2026 proposed rate change				
(000s)	Existing (including elasticity adjustment)	Changes	Proposed	Rate Change %
Return on rate base	**$ 84,764**	**$ 19,903**	**$ 104,667**	2.4%
Other costs				
Power supply costs	531,779	(9,391)	522,388	-1.1%
Operating costs	84,156	784	84,940	0.1%
Employee future benefit costs	1,812	-	1,812	-
Deferred cost recoveries and amortization	492	9,396	9,888	1.1%
Depreciation	86,691	-	86,691	0.0%
Income taxes	18,010	9,531	27,541	1.1%
Subtotal	**722,940**	**10,320**	**733,260**	
Total costs and return	**807,704**	**30,223**	**837,927**	
Adjustments				
Other revenue	(11,644)	4,784	(6,860)	0.6%
Interest on security deposits	72	-	72	-
Energy supply cost variance adjustments	(41,152)	5,657	(35,495)	0.7%
Other transfers to RSA	(4,257)	(1,785)	(6,042)	-0.2%
Subtotal	**(56,981)**	**8,656**	**(48,325)**	
Elasticity adjustment	(5,585)	5,585	-	0.7%
2026 Revenue requirement from rates	**745,138**	**44,464**	**789,602**	5.3%
RSA	71,090	(565)	70,525	-0.1%
MTA	20,250	941	21,191	0.1%
Elasticity adjustment	(716)	716	-	0.1%
Billed to customers	**$ 835,762**	**$ 45,556**	**$ 881,318**	**5.5%**

In our review, we have addressed the major components of revenue requirement noted above, except for the return on equity, and our specific comments on each are outlined in the various individual sections of this report. For clarity, while we have commented on the calculated rate of return on rate base, the appropriateness of the return on common equity is beyond the scope of our report.

The effect of all the factors noted in Newfoundland Power's Application reflect an increase in revenue requirement from rates of $19,300,000 in 2025 and $44,464,000 in 2026, which the Company is proposing to obtain by increasing rates effective July 1, 2025 by an average of 5.5%. Please note that this assumes that the 1.5% customer rate increase as proposed in the Company's 2024 Rate of Return on Rate Base Application is approved.

[3] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023, Exhibit 7 and Exhibit 9

4. Power supply, operating and employee future benefit costs

4.1. Power supply costs

4.1.1. Power supply costs not rebased

In the 2025/2026 GRA, Newfoundland Power is proposing not to rebase its forecast power supply energy costs into base rate 2025 and 2026 revenue requirements. This methodology is not consistent with prior general rate applications where Newfoundland Power would rebase its wholesale power supply costs flowing through the annual July 1st rate adjustment into base rate test year revenue requirement. Past methodology would apply the current wholesale rate charged by Hydro to Newfoundland Power to the energy purchased forecasted in those years. The Company indicated that it was not aware of any relevant regulatory precedent in Newfoundland and Labrador or elsewhere to not rebase power supply costs in establishing customer base rates in a general rate application.[4]

Under the proposed methodology, Energy Supply Cost Variance[5] adjustments are included as a reduction to revenue requirement for 2025 and 2026 in the amount of $40,165,000 and $35,395,000, respectively. Under the proposed methodology, the Energy Supply Cost Variance adjustments for 2025 and 2026 would be transferred to the RSA on December 31, 2025 and December 31, 2026, respectively, and consequently form part of the March 31st RSA balance used to determine the July 1st rate adjustment on July 1, 2026 and July 1, 2027, respectively; both have the impact of increasing customer rates on these dates. If wholesale power supply energy costs were rebased as part of the 2025/2026 GRA, the Company estimated the average customer rate increase to be 9.8%, a 4.3% increase from the Company's proposed 5.5% average customer rate increase[6].

In the 2025/2026 GRA, the Company explained that the change in methodology is due to potential material change in marginal energy costs and the uncertainty in the implementation date of a new wholesale rate.

The Company comments regarding the potential change in marginal energy costs relate to the wholesale rate being re-designed as part of Hydro's next GRA, where the second block energy rate will reflect the cost of energy exports in the range of 3 to 5 cents per kWh compared to the existing second block energy rate of 18.165 cents per kWh.

In the 2025/2026 GRA, the Company stated that Hydro expects the earliest timeframe for filing its next GRA to be in the latter half of 2024. However in response to a request for information, the Company noted that the most recent information from Hydro is that it expects the filing to be in 2025. Newfoundland Power has indicated in response to PUB-NP-004 that it "*is currently discussing with Hydro the possibility of implementing a new wholesale rate on January 1, 2025. The implementation of a new wholesale rate would be effected through a separate application by Hydro, as opposed to being part of its next GRA. Newfoundland Power would then file a subsequent application to "flow-through" the new wholesale rate to its customers*".

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[4] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-005.
[5] Energy Supply Costs Variance clause of the RSA 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.
[6] PUB Information Request (i) Schedule A, Attachment 1.

Newfoundland Power anticipates the implementation would be on an interim basis, would continue to be based on Hydro's 2019 test year revenue requirement, and in Newfoundland Power's view, would supersede the requirement to rebase power supply costs as part of the 2025/2026 GRA. In its response to PUB-NP-004, the Company has provided the customer benefits from the implementation of a new wholesale rate on January 1, 2025, as opposed to the rebasing of the power supply costs in the 2025/2026 GRA. Newfoundland Power has also stated that there are no customer benefits in maintaining the current wholesale rate beyond January 1, 2025.[7]

4.1.2. Power supply costs proposed

We have reviewed the Company's purchased power expense forecast for 2024, 2025 and 2026 and have considered the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates at the time of this report. Forecast purchased power expense reflects the utility rate, approved in Order No. P.U. 15 (2023).

Figure 6 – Purchased power 2022-2026

(000s)	Actual 2022	Actual 2023	Forecast 2023	Existing 2024	Existing 2025	Existing 2026
Purchases from Hydro	$ 479,373	$ 513,381	$ 517,940	$ 522,821	$ 533,716	$ 531,779
Demand management incentive ("DMI")	153	(1,398)	(1,000)	-	-	-
	$ 479,526	**$ 511,983**	**$ 516,940**	**$ 522,821**	**$ 533,716**	**$ 531,779**
Year over year percentage change		**6.77%**	**7.80%**	**1.14%**	**2.08%**	**-0.36%**

(000s)	Actual 2022	Actual 2022	Forecast 2023	Existing 2024	Proposed 2025	Proposed 2026
Purchases from Hydro	$ 479,373	$ 513,381	$ 517,940	$ 522,821	$ 530,628	$ 522,388
DMI	153	(1,398)	(1,000)	-	-	-
	$ 479,526	**$ 511,983**	**$ 516,940**	**$ 522,821**	**$ 530,628**	**$ 522,388**
Year over year percentage change		**6.77%**	**7.80%**	**1.14%**	**1.49%**	**-1.55%**

Purchase power expense is expected to increase over 2022 to 2026 by $52,253,000 due to higher purchased power requirements. Actual energy purchases for 2023 were 5,806.3 GWh, or a purchased power expense of $511,983,000. The increase in purchased power costs from 2022 to 2025 forecast is due to higher purchased power requirements resulting from higher electricity sales. Additional energy purchases are costed at the wholesale purchased power second block rate of 18.165 cents per kWh.

The variance between the existing and proposed purchased power numbers for 2025 and 2026 is due to the elasticity impacts associated with the forecast changes in customer rates.

4.1.3. Conclusion – power supply costs

Based upon our analysis, purchased power forecast for 2025/2026 proposed appears consistent with billing rates from Newfoundland and Labrador Hydro using the effective October 1, 2019 and forecast increase in energy sales. We also noted that the Company has not rebased its forecast power supply energy costs into base rate 2025 and 2026 revenue requirements, which is not consistent past practice.

[7] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-004.

4.2. Operating costs (2022 to 2026)

Using the information presented in **Appendix C** and **Appendix D** of our report, the operating costs per customer from actual 2022 to proposed 2026 are as follows:

Figure 7 – Operating costs by customer 2022-2026

	2022A	2023A	2023F	2024F	2025P	2026P
Number of customers	273,764	274,464	275,281	276,444	277,467	278,359
Gross operating expenses (000s)	$ 85,007	$ 82,029	$ 82,623	$ 86,420	$ 93,502	$ 89,844
Gross operating expense per customer	310.51	298.87	300.14	312.61	336.98	322.76
Change Year Over Year		**-3.75%**	**-3.34%**	**4.16%**	**7.80%**	**-4.22%**
Net operating expenses (000s)	$ 76,521	$ 76,647	$ 76,236	$ 81,785	$ 90,025	$ 86,752
Net operating expense per customer	279.51	279.26	276.94	295.85	324.45	311.66
Change Year Over Year		**-0.09%**	**-0.92%**	**6.83%**	**9.67%**	**-3.94%**

Gross operating expense per customer decreased by 3.34% in the 2023 forecast compared to actual 2022 results, while the 2023 actual gross operating costs per customer decreased by 3.75%. The proposed gross operating cost per customer in 2026 is forecasted to be approximately $322.76, which is an increase of $23.89 compared to the actual 2023 results. This represents an effective annual increase of 2.6% each year for the 2024 – 2026 period.

Net operating expense per customer decreased by 0.92% in the 2023 forecast compared to actual 2022 results, while the 2023 actual net operating costs per customer decreased by 0.09%. The proposed net operating cost per customer in 2026 is forecasted to be approximately $311.66, which is an increase of $32.39 compared to the actual 2023 results. This represents an effective annual increase of 3.73% each year for the 2024 – 2026 period.

Our review of operating expenses was conducted using the expenses by function from Exhibit 1 and expenses by breakdown as outlined in Exhibit 2 of the Application. These exhibits provide details of the actual operating expenses for 2022 and forecasted results for 2023-2026. As part of our analysis of operating expenses, we requested the 2023 actual results for both exhibits to provide more accurate comparisons and trend analysis.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in **Appendix D** of our report. The table and graph show that the gross operating cost per kWh decreased from $0.0147/kWh in 2022 to $0.0139/kWh in 2023 forecast, or $0.0138/kWh in the 2023 actual results. The proposed gross operating cost per kWh in 2026 is forecast to be $0.0150/kWh. In comparison to the 2023 actuals, this would be an increase of $0.0012/kWh, which is an effective annual increase of 2.79% each year for the 2024 – 2026 period. This is primarily due to the proposed gross operating expense in 2026 being $7,815,000 greater than the 2023 actual costs. The most significant contributor to the increase relates to general and employee future benefits, which represents $3,793,000 of the total, while electricity supply and customer service costs rose by $2,636,000 and $1,386,000 respectively.

Net operating expenses, presented in **Appendix C**, increased by $10,105,000 (13.18%) from 2023 actual to 2026 proposed.

Our observations and findings based on our detailed review of the individual expense categories are noted below. Where we have identified unusual trends or other concerns with forecast expenses, we have noted these in the respective sections of our report that follow.

4.2.1. Operating expenses – key variances

After performing our analysis of Exhibit 1 "Operating Costs by Function" and Exhibit 2 "Operating Costs by Breakdown", we have identified the following key variances and related explanations provided by the Company for the period of 2022 to 2026:

Figure 8 – Operating costs by function 2022-2026

(000s)	Ref.	2022A	2023A	2023F	2024F	2025P	2026P
Distribution	*[1]*	$ 11,295	$ 10,812	$ 10,755	$ 11,102	$ 11,500	$ 11,919
Transmission		1,143	1,426	1,142	1,171	1,200	1,231
Substations		2,317	2,460	2,344	2,421	2,511	2,604
Power produced		4,009	3,871	4,093	4,210	4,337	4,470
Administrative & engineering support	*[2]*	8,929	9,705	9,429	9,700	10,054	10,425
Telecommunications		1,491	1,655	1,565	1,633	1,662	1,679
Environment	*[3]*	203	367	294	304	346	328
Fleet operations & maintenance		2,191	1,944	2,108	2,149	2,184	2,220
Electricity Supply		**31,578**	**32,240**	**31,730**	**32,690**	**33,794**	**34,876**
Year over year change ($)			**662**	**152**	**960**	**1,104**	**1,082**
Year over year change (%)			**2.10%**	**0.48%**	**3.03%**	**3.38%**	**3.20%**
Customer services		8,069	8,156	8,259	8,305	8,605	8,919
Conservation	*[4]*	585	733	873	828	873	897
Uncollectible bills		2,027	1,971	2,045	2,186	2,222	2,258
Customer services		**10,681**	**10,860**	**11,177**	**11,319**	**11,700**	**12,074**
Year over year change ($)			**179**	**496**	**142**	**381**	**374**
Year over year change (%)			**1.68%**	**4.64%**	**1.27%**	**3.37%**	**3.20%**
Information systems	*[5]*	6,430	7,610	7,264	8,172	8,724	9,150
Financial services	*[6]*	1,777	2,207	2,128	3,180	3,082	2,668
Corporate & employee services	*[7]*	17,850	17,695	17,765	18,856	19,010	19,903
Insurances	*[8]*	2,214	2,425	2,428	2,621	2,773	2,932
General		**28,271**	**29,937**	**29,585**	**32,829**	**33,589**	**34,653**
Year over year change ($)			**1,666**	**1,314**	**3,244**	**760**	**1,064**
Year over year change (%)			**5.89%**	**4.65%**	**10.97%**	**2.32%**	**3.17%**
Gross operating cost		**$ 70,530**	**$ 73,037**	**$ 72,492**	**$ 76,838**	**$ 79,083**	**$ 81,603**
Year over year change ($)			**2,507**	**1,962**	**4,346**	**2,245**	**2,520**
Year over year change (%)			**3.55%**	**2.78%**	**6.00%**	**2.92%**	**3.19%**

Upon inquiry the Company provided the following explanations regarding key variances:

1) Distribution – the Company noted that costs for 2023 are lower than 2022 primarily due to lower costs associated with storm restoration efforts as a result of favorable weather conditions in 2023. The year over year increases for 2024, 2025 and 2026 primary relate to operating labour costs increasing at the weighted labour rate increase for each respective year.
2) Administrative & engineering support – the Company noted that costs for 2023 are higher than 2022 primarily due to changes to General Expenses Capitalized proposed in the Company's 2022/2023 General Rate Application approved in Order No. P.U. 3 (2022).
3) Environment – the Company noted that costs are higher in 2023 due to an increase in labour costs. Additionally, environment costs are forecast to increase in 2025, due to a planned Environment and Safety audit.
4) Conservation – the Company noted that costs for 2023 are higher than 2022 primarily due to a return to normal levels of outreach and events that began in the latter part of 2022 and continued into 2023.

5) Information systems – the Company noted that costs from 2023 forecast through 2026 forecast reflects additional licensing and support costs for third-party hardware and software solutions, including cybersecurity. This includes increased costs associated with: (i) operations and engineering software, such as the Outage Management System, GIS and the Asset Management System; (ii) infrastructure and network management; (iii) cybersecurity management; (iv) business back-office software, such as the Financial Management System; and (v) customer service software, such as the new Customer Information System. The Company has indicated in the 2025/2026 GRA that approximately $2,100,000 in additional licensing and support cost for third party software solutions are the major cause of the increase.
6) Financial services – the Company noted that costs are higher in 2023 primarily due to the increased labour requirement and higher consultant costs. The increase in 2024 is due to the assessment required to address upcoming changes in accounting standards related to converting to International Financial Reporting Standards ("IFRS"). The decrease in 2025 and 2026 are due to lower consultant costs related to IFRS.
7) Corporate & employee services – the Company indicated that costs for 2024 are higher than 2023 primarily as a result of increased labour costs including inflation, two additional operating days in 2024 and increased corporate costs. The increase in 2026 over 2025 is primarily related to an increase in other company fees.
8) Insurances – the Company noted that costs are higher due to increased premiums which is consistent with global trends.

Figure 9 – Operating costs by breakdown 2022-2026

(000s)	Ref	2022A	2023A	2023F	2024F	2025P	2026P
Regular and standby		$ 34,794	$ 34,952	$ 34,820	$ 36,099	$ 37,557	$ 39,156
Temporary	*[1]*	541	697	665	691	721	754
Overtime		3,702	3,583	3,507	3,639	3,801	3,972
Total labour		**39,037**	**39,232**	**38,992**	**40,429**	**42,079**	**43,882**
Year over year change ($)			**(195)**	**(45)**	**1,437**	**1,650**	**1,803**
Year over year change (%)			**-0.50%**	**-0.12%**	**3.69%**	**4.08%**	**4.28%**
Vehicle expenses		2,184	1,940	2,101	2,142	2,177	2,212
Operating materials		1,254	1,336	1,265	1,290	1,311	1,332
Inter-company charges		27	32	27	28	28	29
Plants, subs, system, oper & bldgs		3,716	3,672	3,750	3,823	3,885	3,948
Travel		1,120	1,163	1,148	1,179	1,198	1,217
Tools and clothing allowance		1,372	1,738	1,384	1,411	1,434	1,458
Miscellaneous	*[2]*	1,467	1,574	1,608	1,640	1,663	1,691
Taxes and assessments		1,388	1,308	1,401	1,428	1,451	1,475
Uncollectible bills		2,027	1,971	2,045	2,186	2,222	2,258
Insurance	*[3]*	2,214	2,425	2,428	2,621	2,773	2,932
Severance & other employee cost		156	214	157	160	163	166
Education, training, employee fees	*[4]*	396	564	508	512	520	528
Trustee and directors' fees	*[5]*	687	635	693	760	772	785
Other company fees	*[6]*	2,945	3,544	3,572	5,131	4,771	4,672
Stationery & copying		240	307	242	247	251	255
Equipment rental/ maintenance		671	774	677	690	702	713
Telecommunications		1,655	1,757	1,680	1,748	1,775	1,791
Postage		1,282	1,211	1,221	1,209	1,207	1,203
Advertising		583	614	600	609	622	632
Vegetation management		3,230	3,328	3,259	3,323	3,377	3,432
Computing equipment & software	*[7]*	2,879	3,697	3,734	4,272	4,702	4,992
Total other		**31,493**	**33,804**	**33,500**	**36,409**	**37,004**	**37,721**
Year over year change ($)			**(2,311)**	**2,007**	**2,909**	**595**	**717**
Year over year change (%)			**-7.34%**	**6.37%**	**8.68%**	**1.63%**	**1.94%**
Gross operating cost		**$ 70,530**	**$ 73,036**	**$ 72,492**	**$ 76,838**	**$ 79,083**	**$ 81,603**
Year over year change ($)			**(2,506)**	**1,962**	**4,346**	**2,245**	**2,520**
Year over year change (%)			**-3.55%**	**2.78%**	**6.00%**	**2.92%**	**3.19%**

Upon inquiry the Company provided the following explanations regarding key variances:

1) Temporary labour – the Company noted that costs are higher in 2023 due to an increased requirement for temporary resources in Customer Services and Technology.
2) Miscellaneous – the Company noted that costs are higher in 2023 as the continued effect of the COVID-19 pandemic resulted in limitations to complete planned activities in 2022 such as community outreach events and in-person education and awareness activities. Operating costs in 2023 reflect the ability to complete those planned activities.
3) Insurance – the Company noted that costs are higher in 2023 due to increased premiums, which is consistent with general market trends. The average annual cost increase has been approximately 14% over the last 5 renewal periods. The Company is forecasting insurance premiums to increase at approximately 6% a year for the 2024/2025 and 2025/2026 renewals.
4) Education, training, employee fees – the Company noted that costs are higher in 2023 due primarily to the continued effect of the COVID-19 pandemic limiting group training events from 2020 through 2022. Operating costs in 2023 primarily reflect higher group health and safety training costs when compared to 2022 of approximately $70,000.

5) Trustee and directors' fees – the Company noted that costs are higher in 2024 due to the timing of replacements for retirements and resignations that occurred in 2023. Two replacement Directors were appointed in October 2023 to replace vacancies from February and April 2023. Operating costs in 2024 reflects the full complement of ten Directors.
6) Other company fees – the Company noted that costs for 2023 through 2026 forecast reflect higher consultant costs associated with: (i) regulatory proceedings anticipated over the forecast period, including the Company's 2025/2026 General Rate Application; (ii) upcoming changes in accounting standards related to converting to International Financial Reporting Standards; (iii) NL Hydro proceedings; and, (iv) information technology, including cybersecurity. The decrease in 2025 and 2026 reflects completion of the Company's 2025/2026 GRA in 2024 and lower consultant costs related to IFRS.
7) Computing equipment and software – the Company noted that costs from 2023 forecast through 2026 forecast reflects additional licensing and support costs for third-party hardware and software solutions, including cybersecurity. This includes increased costs associated with: (i) operations and engineering software, such as the Outage Management System, Geographic Information System ("GIS") and the Asset Management System; (ii) infrastructure and network management; (iii) cybersecurity management; (iv) business back office software, such as the Financial Management System; and (v) customer service software, such as the new Customer Information System.

4.2.2. Review of operating costs (2023TY to 2026)

The Company provided a breakdown of the proposed customer rate increase.[8] The breakdown included an increase in operating costs of $13,400,000 or 1.6% of the 5.5% increase to customer rates. Based on this information, we identified areas of operating expenses that warranted additional analysis. Our analysis compared the 2023 test year to 2024 forecast, 2025 proposed, and 2026 proposed amounts to identify the most significant contributors to the increase. The following table summarizes this analysis.

Figure 10 – Operating costs by breakdown 2023TY-2026

(000s)	2023TY	2024F	2024F vs 2023TY	% change	2025P	2025P vs 2024F	% change	2026P	2026P vs 2025P	% change	2026P vs 2023TY	% change
Regular and standby	$ 33,148	$ 36,099	**$ 2,951**	**9%**	$ 37,557	**$ 1,458**	**4%**	$ 39,156	**$ 1,599**	**4%**	**$ 6,008**	**18%**
Temporary	2,108	691	**(1,417)**	**-67%**	721	**30**	**4%**	754	**33**	**5%**	**(1,354)**	**-64%**
Overtime	3,537	3,639	**102**	**3%**	3,801	**162**	**4%**	3,972	**171**	**4%**	**435**	**12%**
Total labour	**38,793**	**40,429**	**1,636**	**4%**	**42,079**	**1,650**	**4%**	**43,882**	**1,803**	**4%**	**5,089**	**13%**
Vehicle expenses	1,730	2,142	**412**	**24%**	2,177	**35**	**2%**	2,212	**35**	**2%**	**482**	**28%**
Operating materials	1,287	1,290	**3**	**0%**	1,311	**21**	**2%**	1,332	**21**	**2%**	**45**	**3%**
Inter-company charges	28	28	**-**	**0%**	28	**-**	**0%**	29	**1**	**4%**	**1**	**4%**
Plants, subs, system, oper & bldgs	3,492	3,823	**331**	**9%**	3,885	**62**	**2%**	3,948	**63**	**2%**	**456**	**13%**
Travel	891	1,179	**288**	**32%**	1,198	**19**	**2%**	1,217	**19**	**2%**	**326**	**37%**
Tools and clothing allowance	1,265	1,411	**146**	**12%**	1,434	**23**	**2%**	1,458	**24**	**2%**	**193**	**15%**
Miscellaneous	1,595	1,640	**45**	**3%**	1,663	**23**	**1%**	1,691	**28**	**2%**	**96**	**6%**
Taxes and assessments	1,181	1,428	**247**	**21%**	1,451	**23**	**2%**	1,475	**24**	**2%**	**294**	**25%**
Uncollectible bills	2,208	2,186	**(22)**	**-1%**	2,222	**36**	**2%**	2,258	**36**	**2%**	**50**	**2%**
Insurance	2,345	2,621	**276**	**12%**	2,773	**152**	**6%**	2,932	**159**	**6%**	**587**	**25%**
Severance & other employee cost	133	160	**27**	**20%**	163	**3**	**2%**	166	**3**	**2%**	**33**	**25%**
Education, training, employee fees	354	512	**158**	**45%**	520	**8**	**2%**	528	**8**	**2%**	**174**	**49%**
Trustee and directors' fees	712	760	**48**	**7%**	772	**12**	**2%**	785	**13**	**2%**	**73**	**10%**
Other company fees	2,574	5,131	**2,557**	**99%**	4,771	**(360)**	**-7%**	4,672	**(99)**	**-2%**	**2,098**	**82%**
Stationery & copying	260	247	**(13)**	**-5%**	251	**4**	**2%**	255	**4**	**2%**	**(5)**	**-2%**
Equipment rental/ maintenance	897	690	**(207)**	**-23%**	702	**12**	**2%**	713	**11**	**2%**	**(184)**	**-21%**
Telecommunications	1,588	1,748	**160**	**10%**	1,775	**27**	**2%**	1,791	**16**	**1%**	**203**	**13%**
Postage	1,202	1,209	**7**	**1%**	1,207	**(2)**	**0%**	1,203	**(4)**	**0%**	**1**	**0%**
Advertising	534	609	**75**	**14%**	622	**13**	**2%**	632	**10**	**2%**	**98**	**18%**
Vegetation management	2,441	3,323	**882**	**36%**	3,377	**54**	**2%**	3,432	**55**	**2%**	**991**	**41%**
Computing equipment & software	3,446	4,272	**826**	**24%**	4,702	**430**	**10%**	4,992	**290**	**6%**	**1,546**	**45%**
Total other	**30,163**	**36,409**	**6,246**	**21%**	**37,004**	**595**	**2%**	**37,721**	**717**	**2%**	**7,558**	**25%**
Gross operating	**68,956**	**76,838**	**7,882**	**11%**	**79,083**	**2,245**	**3%**	**81,603**	**2,520**	**3%**	**12,647**	**18%**
Amortization of hearing costs	-	-	**-**	**0%**	200	**200**	**0%**	400	**200**	**100%**	**400**	**0%**
Amortization of CDM Costs	4,581	4,903	**322**	**7%**	5,345	**442**	**9%**	5,659	**314**	**6%**	**1,078**	**100%**
Amortizations of electrification costs	-	-	**-**	**0%**	309	**309**	**0%**	384	**75**	**24%**	**384**	**0%**
Transfers to GEC	(2,812)	(2,966)	**(154)**	**5%**	(3,034)	**(68)**	**2%**	(3,106)	**(72)**	**2%**	**(294)**	**10%**
Regulated operating costs	**70,725**	**78,775**	**8,050**	**11%**	**81,903**	**3,128**	**4%**	**84,940**	**3,037**	**4%**	**14,215**	**20%**
Employee future benefits costs	**2,771**	**3,010**	**239**	**9%**	**8,122**	**5,112**	**170%**	**1,812**	**(6,310)**	**-78%**	**(959)**	**-35%**
Total of operating and employee future benefits costs	**$ 73,496**	**$ 81,785**	**$ 8,289**	**11%**	**$ 90,025**	**$ 8,240**	**10%**	**$ 86,752**	**$ (3,273)**	**-4%**	**$ 13,256**	**18%**

Based on the above, we selected the following cost categories for further inquiry and analysis.

- Total labour
- Vehicle expenses
- Plants, substations, system operations and buildings
- Insurance
- Other company fees
- Vegetation management
- Computing equipment and software

[8] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-002

- Amortizations, and
- Employee future benefits

4.2.3. Conclusion – operating costs

Based upon our initial trend analysis and review, we have not yet concluded on the 2024, 2025 and 2026 forecast operating expenses. There are some matters we have identified that require additional analysis. These matters include: 1) total labour; 2) vehicle expenses; 3) plants, substations, system operations and buildings; 4) insurance; 5) other company fees; 6) vegetation management; and 7) computing equipment and software. Our comments in this report reflect our observations and recommendations as of the date of this report. We will provide any further observations and recommendations in a supplemental report to the Board.

4.3. Executive compensation

The following table provides a summary and comparison of regulated executive compensation for forecast 2024, 2025 and 2026 with actuals for 2022 and 2023.

Figure 11 – Average compensation per executive 2022-2026

	Base Salary	Incentive[1]	Other	Regulated	% Change
Forecast 2026[2]					
Total executive group	$ 1,601,000	$ 542,000	$ 146,000	$ 2,289,000	4.5%
Average per executive	400,250	135,500	36,500	572,250	
Forecast 2025[2]					
Total executive group	$ 1,532,000	$ 519,000	$ 139,000	$ 2,190,000	4.4%
Average per executive	383,000	129,750	34,750	547,500	
Forecast 2024					
Total executive group	$ 1,467,000	$ 497,000	$ 134,000	$ 2,098,000	2.4%
Average per executive	366,750	124,250	33,500	524,500	
Actual 2023					
Total executive group	$ 1,413,000	$ 481,000	$ 154,000	$ 2,048,000	4.5%
Average per executive	353,250	120,250	38,500	512,000	
Actual 2022					
Total executive group	$ 1,367,000	$ 468,000	$ 125,000	$ 1,960,000	
Average per executive	341,750	117,000	31,250	490,000	

[1] Incentives reflect regulated portions based on achievement of 100% of corporate and individual targets.

[2] For 2025 and 2026 forecast, the totals reflect labour inflation of 4.45% and 4.50% respectively.

The Company indicated that they engaged Korn Ferry Limited ("Korn Ferry") to provide external expertise to assist with the review of salaries and wages for the executive and senior management employees. On November 2, 2023, Korn Ferry provided a report titled "Executive Compensation – 2024 Estimated Market Actual Salary Median" (the "Korn Ferry report" or the "report"). The report provides an estimate of the market annual salary levels in 2024 for members of Newfoundland Power's executive team. This analysis was based upon Commercial Industrial market data in effect on May 1, 2023. The Korn Ferry report recommends that the Company's executive salary be compared to actual salaries paid by the Commercial Industrial executive market reference group.

The Company's current policy for executive compensation is to establish salaries based on the median of the reference group. Annual increases to executive compensation are set by the Company's Board of Directors on the basis of the information provided by Korn Ferry and individual performance considerations.

In 2024, the Company's executive salary policy versus the actual base salary for executives is outlined in the table below:

Figure 12 – Executive compensation – actual vs. policy

Position	Base Salary[1]	Salary Policy[2]	Korn Ferry Median[3]	Difference From Policy	Base as % of Policy
President & CEO	$ 495,000	$ 510,200	$ 510,200	$ (15,200)	97%
VP customer operations	286,000	345,100	345,100	(59,100)	83%
VP finance & CFO	345,000	345,100	345,100	(100)	100%
VP engineering & energy supply	345,000	345,100	345,100	(100)	100%
Total	**$ 1,471,000**	**$ 1,545,500**	**$ 1,545,500**	**$ (74,500)**	**95%**

[1] *Provided by the Company.*

[2] *Provided by the Company based on advice of Korn Ferry, from actual data collected in August 2023.*

[3] *Korn Ferry median from letter dated November 2, 2023.*

4.3.1. Short-Term Incentive ("STI") program

Newfoundland Power's Executives and Directors participate in the Company's Short-Term Incentive ("STI") program. The Company has indicated that the underlying rationale for the STI program is to incent senior management performance by making a significant portion of total compensation dependent on performance.

The Company has stated that corporate performance targets are set by the Company's Board of Directors. Corporate targets and weightings are reviewed annually and may be modified to reflect changes in corporate focus and priority. The corporate targets consistently focus on performance in the areas of safety, reliability, and customer service, as well as financial and regulatory performance and operating cost management. The Company has provided the following information pertaining to their STI program corporate performance measures from 2024:

- **<u>Earnings and controllable operating costs per customer:</u>**
  Earnings and controllable operating cost per customer targets are based on the Company's annual financial budget, as approved by the Company's Board of Directors. The budget is based on achieving the allowed regulated return on equity.

- **<u>Duration of outages – (SAIDI):</u>**
  Reliability performance is based on the system average interruption duration index ("SAIDI"), which represents the reliability of the power system in terms of the average duration of customer outages. The target is the average of the past five years, excluding the impact of major events and loss of supply from Hydro, which aligns with the Company's strategy of maintaining existing levels of electrical system reliability.

- **Customer satisfaction:**
  Customer satisfaction is measured through independently conducted quarterly customer surveys on Newfoundland Power's service. The customer satisfaction target for 2024 is the same as the target for 2023, which was based on the average of the past five years.

- **Safety:**
  All injury frequency rate – The target for all injury frequency rate is based on the average number of injuries over the past three years.

  Quality leading indicators – Performance measure is made up of two metrics: (i) quality of incident investigations; and (ii) quality of job safety planning. The targets are based on the average performance over the past two years, with a 2% improvement factor.

- **Regulatory Performance:**
  The assessment of regulatory performance will be determined by the Company's Board of Directors. While it is subjective, the Board of Directors will consider the outcome of regulatory proceedings in 2024 including the 2024 Rate of Return on Rate Base Application, the 2025/2026 General Rate Application, the 2025 Capital Budget Application, the Essential Employees Application and other routine filings. Assessment of performance will also consider the volume and complexity associated with the various regulatory proceedings.

The following table outlines the actual results for corporate performance for 2022 and 2023 and targets for 2024:

Figure 13 – Short-term incentive targets and actuals 2022-2024

Measure[1]	2022 Target	2022 Actual	2023 Target	2023 Actual	2024 Target
Controllable operating cost per customer	$ 244.30	$ 257.70	$ 254.70	$ 265.00	$ 270.50
Earnings (millions)	44.00	45.70	45.50	46.00	49.20
Duration of outages (SAIDI)	2.55	3.02	2.69	2.62	2.69
Customer satisfaction	86.8%	87.2%	86.9%	87.4%	86.9%
Cash flow from operating activities (millions)[2]	$ 117.60	$ 120.10	$ 127.40	$ 127.90	NA
Safety (all injury frequency rate)	0.56	0.73	0.56	0.17	0.56
Safety (quality leading indicators)	NA	NA	86.90%	87.40%	91.80%
Regulatory performance	NA	NA	NA	NA	Subjective

[1] The Company has indicated that targets for 2025 and 2026 have not been finalized or approved by the Board of Directors at the time of this report.

[2] Before working capital adjustments.

The program operates to provide 100% payout of established STI if the Company meets, on average, 100% of its performance targets.

For 2022, measures relating to "Earnings", "Cash Flow from Operating Activities", and "Customer Satisfaction - % Satisfied" metrics were met, however, "Controllable Operating Costs/Customer", "SAIDI" and "Injury Frequency Rate" metrics fell below target.
For 2023, all measures were met except, "controllable operating cost per customer" metric.
During our review we noted that the Company removed the 'Cash flow from operating activities' from its corporate performance measures for 2024 and replaced it with 'Regulatory

Performance'. We asked the Company the reason for changing the STI and they provided the following response:

> ***"Cash Flow From Operating Activities***
> *In 2019, cash flow from operating activities was added as a corporate performance measure as part of the Company's STI plan. Cash flow from operating activities, before working capital adjustments, is a key financial metric used by credit rating agencies in assessing the Company's creditworthiness. This STI target measured actual cash flow results compared to the Company's budget.*
>
> *From 2019 to 2023, cash flow from operating activities fluctuated, largely due to the operation of the Energy Supply Cost Variance Clause and the current wholesale rate structure. These fluctuations were largely outside of management's control. Targets that are largely outside the control of management are not effective in incenting performance. As a result, this corporate performance measure was removed in 2024.*
>
> ***Regulatory Performance***
> *Regulation is the Company's key business risk. Newfoundland Power is subject to normal uncertainty facing utilities that operate under cost of service regulation. The Company is dependent on regulatory approval of customer rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing electricity service, including a fair and reasonable return on rate base. Newfoundland Power is also dependent on regulatory approval of its annual capital budget. Finally, regulation is a key consideration by rating agencies in assessing the Company's creditworthiness and ability to maintain sound credit ratings."*

The Company's STI program also includes an individual performance measure for Executives and Directors. This measure is used to reinforce the accountability and achievement of individual performance targets.

The weight between corporate performance and individual performance differs between the managerial classifications, as outlined in the following table:

Figure 14 – Short-term incentive performance weightings

Classification	Corporate Performance	Individual Performance
President and CEO	70%	30%
Vice-Presidents	70%	30%
Directors	50%	50%

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2022 and 2023, as well as for forecast targets for 2024, 2025 and 2026:

Figure 15 – Short term incentive payout as a percent of base pay 2022-2026

	2022 Target	2022 Actual[1]	2023 Target	2023 Actual[1]	2024 Target	2025 Target	2026 Target
President & CEO	50%	51%	50%	57%	50%	50%	50%
VP customer operations	40%	41%	35%	46%	35%	35%	35%
VP finance & CFO	35%	37%	35%	45%	35%	35%	35%
VP engineering & energy supp	35%	36%	35%	43%	35%	35%	35%
Directors	15%	17%	19%	20%	15%	15%	15%

[1] *NLH-NP-114*

The forecast STI payout for 2024 includes assumptions regarding the corporate performance as outlined in the table above.

In dollar terms, the actual STI and other compensation for 2022 and 2023, as well as, forecast payouts for 2024, 2025, and 2026 are summarized in the below table:

Figure 16 – Short term incentive and other compensation by category 2022-2026

(000s)	2022A	2023A	2024F[1]	2025P[1]	2026P[1]
Executive STI[2]	$ 468	$ 481	$ 497	$ 519	$ 542
Directors STI[2]	313	302	323	337	353
Total STI	**781**	**783**	**820**	**856**	**895**
Executive other	125	154	134	139	146
Directors other	201	229	215	224	234
Total other	**326**	**383**	**349**	**363**	**380**
Regulated cost	**1,107**	**1,166**	**1,169**	**1,219**	**1,275**
Executives	838	850	1230	1216	1281
Directors	178	73	35	37	39
Non-regulated cost	**$ 1,016**	**$ 923**	**$ 1,265**	**$ 1,253**	**$ 1,320**

[1] *2024, 2025 and 2026 forecast amounts were inflated by 3.8% and 4.45% and 4.5% respectively.*
[2] *Incentives reflect regulated portion based on achievement of 100% of corporate and individual targets.*

The Company has stated that STI payouts exceeding 100% of the target percentage payout are charged to non-regulated expenses.[9] Additionally, the Company is proposing that 50% of the STI payout relating to earnings, regulatory performance and cash flow from operating activities be charged to non-regulated expenses. This is consistent with Order Nos. P.U. 18 (2016) and P.U. 3 (2022) where the Board ordered that 50% of the STI payout be charged to non-regulated expenses. In 2019 the Company changed its STI measure from regulatory performance to cash flow from operating costs, which continued until 2023. As discussed above the Company changed its STI measure from cash flow from operating costs to regulatory performance in 2024. However, it is important to note that the Board has not formally approved the STI measure or 50% inclusion rate in non-regulated expenses as at the date of this report.

[9] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-31

The following table provides the calculation of these non-regulated expenses for 2023 forecast as provided by the Company:

Figure 17 –STI calculations 2023 forecast for Earnings, Regulatory and Cash Flows

(000s)	2023 STI[1]	Regulatory	Earnings	Cash Flow	Total	Regulated (50%)	Non-Regulated (50%)	Total
Executive	$ 573	$ 7	$ 141	$ 40	$ 188	$ 94	$ 94	$ 188
Directors	345	-	52	17	69	35	35	69
Total	**$ 918**	**$ 7**	**$ 193**	**$ 57**	**$ 257**	**$ 129**	**$ 129**	**$ 257**

[1] 2023 STI forecast is based on achieving 100% of targets.

4.3.2. Conclusion – executive compensation

We reviewed the methodology and supporting documentation for executive compensation and the resulting amounts included in forecast years for any unusual trends. Based on this review, the calculation of forecasted executive compensation for 2025, and 2026 is consistent with past practice.

4.4. Salaries and benefits

Our review of salaries and benefits included an analysis of variances and trends in labour costs, as well as investigation of any significant variances. A detailed comparison of the number of full-time equivalent ("FTE") employees for 2022 to forecast 2026 is as follows:

Figure 18 – Full-time equivalents

	2022A	2023A	2024F	2025P	2026P
Permanent	609.0	629.2	609.4	610.0	609.5
Temporary	21.0	28.2	22.6	23.0	22.5
Total	**630.0**	**657.4**	**632.0**	**633.0**	**632.0**
Managerial FTE`s	291.6	307.6	297.0	297.6	297.1
% managerial	**46%**	**47%**	**47%**	**47%**	**47%**
Union FTE`s	317.4	321.6	312.4	312.4	312.4
% union	**50%**	**49%**	**49%**	**49%**	**49%**

According to the Company, FTEs and labour are forecasted by performing the following:

- The Company first estimates the total forecast labour requirement, which is a function of the annual capital and operational work requirement. Capital is principally based on specific expenditures to replace equipment and serve forecast customer growth, while operating is focused on the maintenance and operation of the electrical system, response to customer inquiries, and commercial functions.
- The Company then estimates available internal labour on an FTE basis, making necessary adjustments for anticipated retirements, leaves of absence, terminations, and new hires. These adjustments are fully reflected in both forecast FTE's and internal labour costs.

- The Company then reconciles any difference between required and available by using contract labour.

In the previous GRA, Newfoundland Power forecasted that FTEs would increase by 12 and 18 in 2021 and 2022, respectively. These increases were primarily in relation to the Customer Service System ("CSS") replacement project, which was delayed, resulting in these approximate increases being realized in 2022 and 2023.

The 2024 forecast for the current GRA shows a decrease of 25 FTE's, which is primarily due to the expected conclusion of the CSS replacement project that will result in the termination of 22.7 FTE's and decreased labour costs of $3,068,000.

Both 2025 and 2026 FTE's are forecast to remain relatively stable, with no significant events noted that would cause abnormal fluctuations. In both cases the adjustments are related to employees leaving or joining the Company in the normal course of operations. As part of our review, we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 2022 to forecast 2026 are included in the table below:

Figure 19 – Salary cost per full time equivalent

(000s)	2022A	2023A	2023F	2024F	2025P	2026P
Salary costs	$ 72,915	$ 81,324	$ 81,719	$ 81,767	$ 84,974	$ 88,610
Benefit costs (net)	(9,922)	(15,134)	(15,134)	(15,709)	(16,408)	(17,147)
Other adjustments	(735)	-	-	(602)	(302)	(316)
Base salary costs	**62,258**	**66,190**	**66,585**	**65,456**	**68,264**	**71,147**
Less: executive compensation	(1,943)	(2,101)	(1,986)	(2,061)	(2,153)	(2,250)
Base salary costs (excluding executive)	**$60,315**	**$64,089**	**$64,599**	**$63,395**	**$66,111**	**$68,897**
FTE's (including executive members)	630	657	655	632	633	632
Average salary per FTE	**$98.8**	**$100.7**	**$101.7**	**$103.6**	**$107.8**	**$112.6**
% increase		**1.88%**	**2.87%**	**1.88%**	**4.12%**	**4.39%**
FTE's (excluding executive members)	626	653	651	628	629	628
Average salary per FTE	**$96.3**	**$98.1**	**$99.2**	**$100.9**	**$105.1**	**$109.7**
% increase		**1.80%**	**2.99%**	**1.73%**	**4.12%**	**4.38%**

In the *"Labour Forecast 2025-2026"* report, the Company has noted that the 2025 and 2026 salary increase is based on a weighted average salary increase of 4.45% and 4.5% respectively. In both cases the average salary per FTE appears to be consistent with the annual weighted labour rate increase. The following table provides the breakdown of the Company's weighted labour rate from 2022-2026.

Figure 20 – Weighted labour rate

(%)	Actual 2022	Actual 2023	Forecast 2024	Forecast 2025	Forecast 2026
Base Rate[1]	2.25	2.00	3.05	3.70	3.75
Progression Rate[2]	0.75	0.75	0.75	0.75	0.75
Total	**3.00**	**2.75**	**3.80**	**4.45**	**4.50**

[1] Base rate reflects the Company's collectively bargained annual increases agreed to between the Company and its union and market changes for non-union employees. Newfoundland Power had two collective agreements in effect until June 30, 2022. For 2023 through 2026 forecast, annual labour inflation reflects (i) the Clerical collective agreement that was signed effective November 11, 2023, and (ii) the tentative collective agreement reached between Newfoundland Power and the IBEW for the Craft bargaining unit. The Craft tentative agreement was not ratified.

[2] Progression rate reflects the additional wage employee's receive as they progress through their position. For union employees, labour progression is included in the Collective Agreement. For example, a Powerline Technician ("PLT") Apprentice will start at 70% of the Tradesperson's rate and over a 4-year period, increase to 95% of the Tradesperson's rate. For non-union employees, they typically enter a position between 80% and 100% of full salary, depending on their experience, and are expected to progress to full salary within 5 years. An estimate of 0.75% progression was used in the weighted labour inflation calculations for the 2025/2026 General Rate Application.

The following table provides the detailed breakdown of forecast labour expenses as per the Company's "Labour Forecast 2023-2026" report and in response to a request for information.[10]

Figure 21 – Internal labour forecast 2023-2026

(000s)	2022A	2023A	2023F	2024F	2025P	2026P	Effective Annual % Change (2026-2022)
Operating	$ 35,335	$ 35,649	$ 35,485	$ 36,790	$ 38,278	$ 39,910	**3.09%**
Capital	25,048	30,057	30,019	28,368	29,576	30,873	**5.37%**
Rechargeable & Recoverable	8,984	9,753	9,852	10,306	10,674	11,078	**5.38%**
Total[1]	**$ 69,367**	**$ 75,459**	**$ 75,356**	**$ 75,464**	**$ 78,528**	**$ 81,861**	**4.23%**

[1] The Internal Labour Forecast totals presented above and the internal labour figure presented in the below table "Salary Costs by Function" are different due to the inclusion of the non-regulated labour, CDM program labour, electrification program labour, and pension and OPEB currrent service costs.

[10] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-94

An analysis of salaries and wages by type of labour and by function within the Company is as follows:

Figure 22 – Salary costs by function 2022-2026

(000s)	2022A	2023A	2023F	2024F	2025P	2026P	Effective Annual % Change (2026-2022)
Type							
Internal labour	$ 72,915	$ 81,324	$ 81,719	$ 81,767	$ 84,974	$ 88,610	**4.99%**
Overtime	7,251	7,116	6,591	6,841	7,146	7,467	**0.74%**
	80,166	88,440	88,310	88,608	92,120	96,077	**4.63%**
Contractors	16,446	21,912	16,502	16,923	17,164	17,433	**1.47%**
Total	**$ 96,612**	**$ 110,352**	**$ 104,812**	**$ 105,532**	**$ 109,283**	**$ 113,510**	**4.11%**
Function							
Operating[1]	42,605	45,138	45,402	46,778	48,570	50,676	**4.43%**
Capital miscellaneous	54,007	65,214	59,410	58,754	60,713	62,834	**3.86%**
Total	**$ 96,612**	**$ 110,352**	**$ 104,812**	**$ 105,532**	**$ 109,283**	**$ 113,510**	**4.11%**

[1] The operating labour figures provided in Exhibit 2 for 2022 to 2026 forecast exclude non-regulated expenses, CDM program labour, electrification program labour, and Pension and OPEB current service costs. A reconciliation between above table for operating and Exhibit 2 as provided by the Company is as follows:

Operating Labour, Exhibit 2	**$ 39,037**	**$ 39,232**	**$ 38,992**	**$ 40,429**	**$ 42,079**	**$ 43,882**	**2.97%**
Non-regulated labour	1,016	923	1,163	1,265	1,253	1,320	
CDM program labour	1,102	1,287	1,452	1,419	1,439	1,489	
Electrification program labour	18	17	97	103	105	109	
OPEB current service costs	1,432	759	758	788	820	853	
Pension current service costs	-	2,920	2,940	2,774	2,874	3,024	
Operating labour, above	**$ 42,605**	**$ 45,138**	**$ 45,402**	**$ 46,778**	**$ 48,570**	**$ 50,676**	4.43%

According to the Company, operating labour costs presented in Exhibit 2 is forecast to increase by $4,800,000, or 12.4%, from 2022 – 2026, which is a 3.1% increase annually [12.4% / 4 years = 3.1%]; we have calculated an effective annual rate increase of 2.97%. The Company added that this represents a 1% efficiency compared to increasing the 2022 costs using the Company's weighted labour rate for 2023 – 2026, as this would result in a total increase $6,407,000 or 16.4%, which is an increase of 4.1% annually.

4.4.1. Conclusion – salaries and benefits

Based upon our initial review, we have not yet concluded on employee salaries and benefits. We will make our comments in a supplemental report to the Board.

4.5. Employee future benefits

The Company maintains plans for its employees which provide for benefits upon retirement. The Company has grouped these into two broad categories: pension plans and other post-employment benefits ("OPEBs") plans. The components of employee future benefits expense are as follows:

Figure 23 – Employee future benefits breakdown 2022-2026

(000s)	Actual 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026
Pension expense	$ (63)	$ (4,006)	$ (3,886)	$ 1,098	$ (1,824)
OPEBs expense	7,715	6,769	6,896	7,024	3,636
Total	**$ 7,652**	**$ 2,763**	**$ 3,010**	**$ 8,122**	**$ 1,812**

4.5.1. Company pension plan

For the 2022 – 2026 period, we reviewed the individual components and the estimates supporting them in calculating the total pension. The components of pension expense are as follows:

Figure 24 – Pension expense breakdown – 2022-2026

(000s)	Actual 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026
Defined benefit pension plan:					
Defined benefit pension expense	$ (3,479)	$ (4,826)	$ (5,302)	$ (704)	$ (3,865)
PUP/SERP[1]	354	433	439	445	450
Less defined benefit costs capitalized[2]	-	(1,277)	(900)	(760)	(716)
Total	**(3,125)**	**(5,670)**	**(5,763)**	**(1,019)**	**(4,131)**
Defined Contribution Pension Plan:					
Group and individual RRSPs	3,062	3,326	3,748	4,228	4,615
Less: RRSP costs capitalized[2]	-	(1,663)	(1,874)	(2,114)	(2,308)
Total	**3,062**	**1,663**	**1,874**	**2,114**	**2,307**
Total pension expense[3]	**$ (63)**	**$ (4,007)**	**$ (3,889)**	**$ 1,095**	**$ (1,824)**
Year over year % change		**6260%**	**-3%**	**-128%**	**-267%**

[1] Pension uniformity plan ("PUP"); Supplemental employee retirement program ("SERP").

[2] Amounts Capitalized are equal to 50% of the current service costs for the respective plan. No amount capitalized in 2022 as these costs were previously capitalized as a component of General Expenses Capitalized ("GEC").

[3] Total pension expense agrees to the above table which is used to calculate the amount presented on the income statement.

The negative pension expense over the period 2022 to 2026 is primarily due to the expected return on plan assets being higher than the forecast current service and interest costs. The lower current service and interest costs reflect the reduction in active employees and related current service costs in the Defined Benefit Pension Plan (the "DB Plan") since its closure in 2004, as well as a reduction in defined benefit plan obligations. The increase in pension expenses in 2025 is related to a $3.2 million amortization of actuarial losses from 2023 compared to prior years presented ($Nil for 2022 to 2024). We compared the forecasted amounts for the defined benefit pension expense to actuary tables and found no exceptions.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in Order No. P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent, and properly chargeable to the operating account of the Company.

Newfoundland Power's DB Plan was created in 1984 and closed to new entrants in 2004. Since that time, all new employees are enrolled into the Company's Individual RRSP Plan, funded 50% by the Company. According to the Company, the increases in RRSP costs over the forecast period 2022 to 2026 reflects: (i) the retirement of employees who were part of the DB Plan and replacement by new employees who are enrolled in the Individual RRSP Plan, (ii) normal increases in compensation, and (iii) higher employer RRSP contributions. According to the Company, the RRSP employer contributions are forecast to increase by 0.25% effective January 1, 2024 and another 0.25% effective January 1, 2025 based on the current Clerical Collective Agreement between Newfoundland Power and its union, and the tentative Craft Collective Agreement, which was not ratified.

4.5.2. Other post-employment benefits ("OPEBs")

In its 2010 General Rate Application, the Company proposed the implementation of the accrual method of accounting for OPEBs expenses. The proposal included a deferral mechanism to capture annual variances arising from changes in the discount rate and other assumptions, and recommendations related to the recovery of the transitional balance associated with the adoption of accrual accounting for OPEBs costs. In Order No. P.U. 31 (2010) the Board decided the Company should use the accrual method of accounting for OPEBs costs and income tax related to OPEBs as of January 1, 2011.

The Board also required that the transitional balance for OPEBs expense be amortized using the straight-line method over a period of 15 years. The Board also approved the creation of the OPEBs Cost Variance Deferral Account to limit the variability of the OPEBs costs due to changing assumptions such as discount rates. The components of OPEBs expense for 2022 – 2026 are as follows:

Figure 25 – Other post-employment benefits breakdown 2022-2026

(000s)	Actual 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026
OPEBs accrual	$ 5,507	$ 4,026	$ 4,186	$ 4,340	$ 4,488
Amortization of transitional asset	3,504	3,504	3,504	3,504	-
Less capitalized portion of OPEBs[1]	(1,296)	(758)	(788)	(820)	(853)
Total OPEBs expense	**$ 7,715**	**$ 6,772**	**$ 6,902**	**$ 7,024**	**$ 3,635**
Year over year % change		**-12%**	**2%**	**2%**	**-48%**

[1] *Amounts capitalized are equal to 47.5% of current service costs in 2022 and 50% thereafter.*

The reduction in the OPEB's accrual from 2022 to 2023 primarily reflects the increase in the discount rate from 3.2% in 2022 to 5.3% in 2023, and the amortization of an actuarial gain. The nominal increases over the period 2023 to 2025 primarily reflects normal increases in the actuarial liability over the period. The decrease in 2026 reflects the 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. We compared the forecasted amounts of the OPEBs accrual to actuary tables and found no exceptions.

4.5.3. Conclusion – employee future benefits

Based on our review of employee future benefits, nothing has come to our attention that would suggest forecasted employee future benefits for 2025 and 2026 are unreasonable.

4.6. Finance charges

Our procedures with respect to interest on long term debt and other interest included a recalculation of interest charges and assessment of reasonableness based on debt outstanding. The following table summarizes the various components of finance charges:

Figure 26 – Finance charges 2022-2026

(000s)	2022A	2023A	2023F	2024F	2025P	2026P
Interest						
Long-term debt	$ 35,597	$ 36,673	$ 36,677	$ 39,053	$ 38,600	$ 40,860
Other	476	2,619	2,808	3,613	3,604	1,708
Amortization						
Debt issue expense	214	218	221	225	221	217
Deductions						
Debt portion of AFUDC	(824)	(1,468)	(1,316)	(707)	(742)	(933)
Equity portion of AFUDC	(674)	(1,201)	(1,077)	(578)	(607)	(763)
Total finance charges - Exhibit 5	**34,789**	**36,841**	**37,313**	**41,606**	**41,076**	**41,089**
Less: interest on security deposits	(24)	(23)	(76)	(72)	(72)	(72)
Total finance charges - return on rate base	**$ 34,765**	**$ 36,818**	**$ 37,237**	**$ 41,534**	**$ 41,004**	**$ 41,017**
Year over year dollar change		**2,053**	**2,472**	**4,297**	**(530)**	**13**
Year over year percentage change		**5.91%**	**7.11%**	**11.54%**	**-1.28%**	**0.03%**

Finance charges were forecast to increase by $2,472,000 (7.11%) in 2023 compared to 2022, however the 2023 actual results were $2,053,000 (5.91%) greater than in 2022. The most notable contributors to the increase in actual 2023 costs are $1,076,000 of additional interest on long term debt and $2,143,000 of other interest, partially offset by a $1,171,000 increase for AFUDC deductions. There is another significant increase forecasted in 2024 of $4,297,000 (11.54%) compared to the 2023 forecast. This is due to increased interest on long term debt of $2,376,000 and other interest costs of $805,000, plus a reduction in AFUDC deductions of $1,108,000. For the proposed 2025 forecast, there is a decrease of $530,000 which primarily relates to decreased interest on long term debt of $453,000. The proposed 2026 forecast has little change due to an increase of $2,260,000 for interest on long term debt, with an offsetting decrease of $1,896,000 in other interest and increased AFUDC deductions of $347,000.

The increase in interest on long term debt is attributed to the issuance of new long-term debt in April 2022 for $75,000,000 with an interest rate of 4.298%, partially offset by the redemption of debt of $28,400,000 with interest rate of 10.125%, along with an issuance of debt in August 2023 for $90,000,000 at an interest rate of 5.122%. In 2026 there is a planned issuance of debt of $100,000,000, with an expected interest rate of 5.5%. Since all issuances occurred part way through the respective year, the additional interest on long term debt incurred in the year of issue was for a partial year.

In addition to the issuances mentioned, there are significant fluctuations in credit facility costs included in other interest. Credit facility costs increased by $2,121,000 in the actual 2023 results compared to 2022 and are forecast to increase by $1,030,000 again in 2024. The rise in credit facility costs is due to the average short-term rate increasing from 2.45% in 2022 to 5.98% and 5.54%, paired with a year over year increase in average short-term borrowings of $7,793,000 and $17,537,000 in 2023 and 2024, respectively.

Credit facility costs in 2025 is forecast to remain stable compared to 2024 as a result of an increased average short-term borrowings of $9,236,000 offset by a decrease of 78 basis points in short-term borrowing rates. Credit facility costs in 2026 is forecast to decrease by $1,896,000 compared to 2025 due to a reduction in average short-term borrowings of $41,300,000.

The Company has the forecast average short-term borrowing rate to be 5.54% for 2024, 4.75% for 2025, and 4.75% for 2026. We reviewed the short-term interest rates included in the Company’s assumptions and they are consistent with interest rate forecast from the five major banks in Canada.

4.6.1. Conclusion–- finance charges

Based upon our analysis, nothing has come to our attention to indicate that the proposed finance charges for 2025 and 2026 are unreasonable.

4.7. Intercompany charges

Our review of Intercompany Charges included the following specific procedures:

- assessed the Company's compliance with Order No.'s P.U. 19 (2003), P.U 32 (2007) and P.U. 43 (2009) and P.U 13 (2013); and,
- compared charges for 2024, 2025 and 2026 forecast to previous years and obtained explanations for unusual fluctuations and trends.

According to the Company, charges from Fortis Inc. ("Fortis") are generally based on actual invoice costs or Newfoundland Power's usage of a specific service. For charges from Fortis that are based on a specific allocation, Fortis continues to allocate recoverable costs based on subsidiaries' assets, consistent with its methodology in the past. Differences between forecast and actual costs are adjusted in the subsequent year. According to the Company these adjustments have historically been less than 5% of total annual costs.

The following tables provides a breakdown of inter-corporate charges from/to affiliates during 2022 and 2023, including forecast charges for 2024, 2025 and 2026:

Figure 27 – Charges from affiliates including Fortis Inc. 2022–- 2026F

Intercompany transactions	Actual 2022	Actual 2023	Forecast 2024	Forecast 2025	Forecast 2026
Charges from Affiliates including Fortis Inc.					
Trustee & share plan costs[1]	$ 27,000	$ 32,000	$ 28,000	$ 28,000	$ 29,000
Staff charges[2]	-	-	-	-	-
Miscellaneous[3]	490,000	540,000	529,000	503,000	505,000
Total	**$ 517,000**	**$ 572,000**	**$ 557,000**	**$ 531,000**	**$ 534,000**
Year over year percentage change		**11%**	**-3%**	**-5%**	**1%**

[1] Includes costs related to the employee share purchase plan administered by Fortis Inc. These costs are shared amongst all Fortis subsidiary companies.

[2] Includes labour and travel costs relating to services provided to Newfoundland Power by employees of other affiliates.

[3] Includes any and all charges that are not specifically covered by one of the above referenced categories.

Figure 28 – Charges to affiliates including Fortis Inc. 2022-2026F

Intercompany transactions	Actual 2022	Actual 2023	Forecast 2024	Forecast 2025	Forecast 2026
Charges to Affiliates including Fortis Inc.					
Postage[1]	$ 1,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000
Staff charges[2]	1,680,000	27,000	20,000	20,000	21,000
Miscellaneous[3]	515,000	122,000	76,000	77,000	78,000
Total	**$ 2,196,000**	**$ 151,000**	**$ 98,000**	**$ 99,000**	**$ 101,000**
Year over year percentage change		**-93%**	**-35%**	**1%**	**2%**

[1] Includes postage and production center labour charges relating to any mail services provided to affiliates.

[2] Includes labour and travel expenses related to work performed on projects by Newfoundland Power employees for any of its affiliates. Staff charges were higher in 2022 primarily as a result of hurricane relief efforts at Maritime Electric after Hurricane Fiona.

[3] Includes any and all charges that are not specifically covered by one of the above referenced categories. Miscellaneous charges were higher in 2022 primarily as a result of hurricane relief efforts at Maritime Electric after Hurricane Fiona.

4.7.1. Conclusion – intercompany charges

Based upon our analysis, intercompany charges are calculated using a methodology that is consistent year over year. As a result of our review, nothing has come to our attention that would lead us to believe that forecast intercompany charges are unreasonable.

4.8. Non-regulated expenses

4.8.1. Review of non-regulated expenses

Our review of non-regulated expenses included the following procedures:

- assess the Company's compliance with Board Orders;
- compared non-regulated expenses for the 2024, 2025 and 2026 forecast to prior years and investigated any unusual fluctuations.

Figure 29 – Non-regulated expenses 2022-2026

(000s)	2022A	2023A	2024F	2025F	2026F
Labour - **Note 1**	1,016	923	1,265	1,253	1,320
Intercompany - **Note 2**	1,844	1,659	1,824	1,867	1,940
Community Relations & Other	361	393	404	410	417
Advertising	13	12	13	14	14
Non-regulated Expenses Before Tax	**3,234**	**2,987**	**3,506**	**3,544**	**3,691**
Less: Income Taxes	(970)	(896)	(1,052)	(1,063)	(1,107)
Non-regulated Expenses After Tax	**2,264**	**2,091**	**2,455**	**2,481**	**2,584**

***Note 1** – The Company provided a breakdown of labour components. Non-regulated labour expense is broken down as follows:*

(000s)	2022A	2023A	2024F	2025F	2026F
Executive Compensation - Stock Related ***[1]***	542	741	1,135	1,119	1,180
STI>100% and Non-regulated Performance Targets	474	182	130	134	140
Total labour components	**1,016**	**923**	**1,265**	**1,253**	**1,320**

***[1]** The Company noted that executive stock related compensation is lower in 2022 and 2023 primarily due to actual performance results being lower than target for those years. The 2024 to 2026 forecast assumes performance results at 100% of target. In addition, the 2024 to 2026 forecast also reflects forecast increases in stock price and changes in the Executive members in 2023.*

***Note 2** – The Company noted that Intercompany charges were lower in 2023 primarily due to a true-up adjustment related to 2022 actual charges versus forecast.*

The 2024, 2025 and 2026 non-regulated expenses have been forecast at $3,506,000, $3,544,000 and $3,691,000 (before tax) respectively, as compared to $2,987,000 in 2023. In compliance with Order No. P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2025 and 2026, the Company has estimated that performance will be at 100% of targets and therefore the expectation is that the STI payout will not exceed 100%. The Company also classified 50% of its short-term incentive payouts related to earnings and regulatory performance components as non-regulated expenses. This is similar to the approach that was approved in Order No. P.U. 18 (2016) when regulatory performance was included as an STI measure. However, including the regulatory performance component as an STI measure has not been approved by the Board and any potential inclusion rate has also not been approved. Details on the short-term incentive payouts are included in this report under the heading STI Program.

4.8.2. Conclusion–- non-regulated expenses

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders. However, the proposed changes to STI measures, specifically the addition of the regulatory performance component as a STI measure and the regulatory expense inclusion rate for STI payments resulting from this metric have not yet been approved by the Board.

5. Deferred cost recoveries and amortization

5.1. Regulatory deferrals

Newfoundland Power has several regulatory deferral accounts whereby the associated amortizations impact the revenue requirement. The amortization of regulatory deferrals is summarized in the table below:

Figure 30 – Amortization of regulatory deferrals 2022-2026

(000s)	2022A	2023F	2024P	2025P	2026P
2022 Revenue shortfall	$ (656)	$ 328	$ 328	$ -	$ -
Pension capitalization deferral	-	(1,144)	(568)	492	492
Hearing costs deferral	-	-	-	200	400
2024 Revenue shortfall	-	-	(6,722)	1,344	2,689
2025 Revenue shortfall	-	-	-	(13,407)	6,707
Revenue requirement impact	**$ (656)**	**$ (816)**	**$ (6,962)**	**$ (11,371)**	**$ 10,288**
Included in revenue requirement:					
Operating costs - hearing costs amortization	**-**	**-**	**-**	**200**	**400**
Amortization of deferrals	**$ (656)**	**$ (816)**	**$ (6,962)**	**$ (11,571)**	**$ 9,888**

5.1.1. Procedures

Our procedures with respect to the regulatory deferrals include the following:

- Reviewed the methodology of proposed regulatory amortization for reasonableness and determined if this was consistent with previously approved practices and/or industry practice; and
- Reviewed the regulatory amortizations previously approved to ensure they are in accordance with decisions outlined by the Board.

5.1.2. Previously approved regulatory deferrals

Certain amortization of regulatory deferrals consists of accounts that were previously approved by the Board as follows:

- **2022 Revenue shortfall:** 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 monthly amortization of approximately $27,000 ($930,000/34 months). For 2022, the revenue shortfall decreased revenue requirement by approximately $656,000 ($930,000 – (27,000*10 months)). For 2023 and 2024, the amortization of the 2022 revenue shortfall was collected and increased revenue requirement by approximately $328,000 per year ($27,000*12 months).

- **Pension capitalization deferral**: In Order No. P.U.3 (2022), the Board approved the revisions to the Company's general expenses capitalized calculation effective January 1, 2023, which included the use of a deferral account to 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. For 2023, the Board approved the forecast revenue requirement increase of $1,427,000 and amortization period over five years. For 2024, the Company has calculated the forecast deferral account to be $1,063,000 and to be amortized over five years in accordance with the deferral account definition. This resulted in a decrease in revenue requirement by approximately $1,144,000 and $568,000 in 2023 and 2024 respectively. In the 2025/2026 GRA, Newfoundland Power is proposing that the Board amend the Pension Capitalization Deferral Account to cease charges to the account effective December 31, 2024. In its Amended 2022/2023 GRA transmittal letter, the Company stated that it intended to use the Pension Capitalization Deferral Account until the full cost of the change in pension capitalization methodology could be reflected in customer rates at the Company's next GRA. The Company has noted that ceasing charges to the account will therefore allow for a more accurate tax treatment. The Company has stated that the income tax effects related to pension capitalization are estimated to be $1.1 million and $1.2 million in 2025 and 2026, respectively. Prior charges to the account will continue to be amortized over five years. This will result in a forecasted impact of $492,000 per year in 2025 and 2026.

5.1.3. Proposed regulatory deferrals

In the 2025/2026 General Rate Application, Newfoundland Power proposed that the Board approve the following additional regulatory deferrals for 2025 and 2026:

- amortize the recovery over a 30-month period of an estimated $1,000,000 in Board and Consumer Advocate costs related to the Application, in addition to any difference between actual and $1,000,000 to be recovered or rebated through the RSA;
- amortize forecast 2024 revenue shortfall of an estimated amount of $6,722,000 over a 30-month period, commencing July 1, 2025; and
- amortize forecast 2025 revenue shortfall of an estimated amount of $16,761,000 over a 30-month period, commencing July 1, 2025.

5.1.4. Review of regulatory deferrals

We reviewed the proposed regulatory deferrals in the 2025/2026 General Rate Application as follows:

- **General Rate Application costs:** With respect to the costs relating to the 2025/2026 GRA, the Company is proposing that these costs be recovered in customer rates evenly over a 30-month period beginning July 1, 2025, and ending December 31, 2027. The Company has also proposed that any difference between actual and $1,000,000 to be recovered or rebated through the RSA. In the settlement agreement for the 2022/2023 GRA, the Board approved the recovery of hearing costs directly through the RSA. In Order No. P.U.2 (2019), the Board accepted the settlement agreement in relation to hearing costs and approved the amortization of estimated hearing costs in an amount of $1,000,000 over a 34-month period, with any difference between actual and $1,000,000 to be collected or rebated through the RSA. The Company's proposal is consistent with the treatment of hearing costs from the 2019/2020 GRA, the only difference being that the amortization period is 30-months, instead of the prior 34-months. This would result in an impact on the proposed revenue requirement of $200,000 in 2025 and $400,000 in 2026.

- **2024 Revenue shortfall:** In the 2024 Rate of Return on Rate Base ("RRORB") Application, the Company proposed a deferred cost recovery of $6,722,000 for the 2024 revenue shortfall; this shortfall and the proposed 1.5% increase in customer rates effective July 1, 2024 is before the Board and remains subject to a Board Order. Based upon a July 1, 2025 implementation, Newfoundland Power is proposing to amortize this amount over 30-months commencing on July 1, 2025 and ending December 31, 2027. This represents monthly amortization of approximately $224,000 ($6,722,000/30 months). For 2025, it represents amortization over 6 months, or an increase to revenue requirement of approximately $1,344,000 ($224,000*6 months). For 2026 and 2027, this represents approximately $2,689,000 per year ($224,000*12 months).

- **<u>2025 Revenue shortfall:</u>** Based upon a July 1, 2025 implementation, customer rates designed to recover the proposed 2026 revenue requirement would result in a $16,761,000 shortfall in the proposed 2025 revenue requirement. Consistent with the 2024 revenue shortfall, the Company is proposing to amortize this amount over 30-months commencing on July 1, 2025 and ending December 31, 2027. This represents monthly amortization of approximately $559,000 ($16,761,000/30 months). For 2025, it represents amortization over 6 months, or an increase to revenue requirement of approximately $3,354,000 ($559,000*6 months). This results in a revenue requirement impact of $13,407,000 ($16,761,000 deferral less $3,354,000 amortization). For 2026 and 2027, this represents approximately $6,707,000 per year ($559,000*12 months).

5.1.5. Conclusion

Based on our review and analysis, nothing has come to our attention to indicate the regulatory deferrals and amortizations included in the Application are unreasonable or not in accordance with relevant Board Orders.

5.2. Conservation and demand management (“CDM”) & electrification cost deferral

In Order No. P.U. 13 (2013), the Board approved the definition for the Conservation and Demand Management Cost Deferral Account and the amortization of annual customer energy conservation program costs over seven years with recovery through the RSA. The definition for the CDM cost deferral account is as follows:

> *“This account shall be charged with the costs incurred in implementing the CDM Program Portfolio. These costs include the CDM Program Portfolio costs incurred by Newfoundland Power for: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, and program evaluation costs. This account shall also be charged the costs of major CDM studies such as comprehensive customer end use surveys and CDM potential studies that cost greater than $100,000. Transfers to, and from, the proposed account will be tax-effected. This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred. Recovery of annual amortizations of costs in this account shall be through the Company’s Rate Stabilization Plan or as otherwise ordered by the Board.”*

At the time the Board approved the definition for the CDM Cost Deferral Account and the amortization of annual customer energy conservation program costs over seven years with recovery through the RSA. In Order No. P.U. 3 (2022), the Board approved to increase the amortization of CDM program costs incurred commencing January 1, 2021, from seven to ten years for both historical balances and annual charges on the basis that this amortization period generally corresponds with the average useful life of the technologies captured by CDM programs.

5.2.1. Procedures

Our procedures with respect to the CDM and electrification cost deferrals include the following:

- Reviewed the methodology of proposed amortization for reasonableness and determined if this was consistent with previously approved practices; and
- Reviewed the amortizations previously approved to ensure they are in accordance with decisions outlined by the Board.

5.2.2. Review of CDM

The following table provides the forecast costs for the Company's customer conservation programs for 2022 and 2023 to 2026 forecast:

Figure 31 – Customer conservation program costs 2022-2026F

(000s)	2022A	2023F	2024F	2025F	2026F
General	$ 426	$ 724	$ 712	$ 714	$ 731
Program	5,227	6,701	6,007	5,774	5,895
Total	**$ 5,653**	**$ 7,425**	**$ 6,719**	**$ 6,488**	**$ 6,626**

Furthermore, the Company provided the following table which provides the breakdown of the CDM program costs for 2022 to 2026 forecast:

Figure 32 – Breakdown of CDM program costs 2022-2026

(000s)	2022A	2023F	2024F	2025F	2026F
Regular labour	$ 1,063	$ 1,376	$ 1,374	$ 1,394	$ 1,443
Temporary labour	19	30	-	-	-
Overtime	19	46	44	45	46
Miscellaneous	142	286	252	251	256
Conservation costs	1,600	1,626	1,822	1,867	1,897
Education & training	19	20	22	23	23
Travel	22	47	28	28	29
Other company fees	1,522	2,242	1,730	1,377	1,399
Advertising	821	1,028	735	789	802
Total	**$ 5,227**	**$ 6,701**	**$ 6,007**	**$ 5,774**	**$ 5,895**

The following table provides the impact of the forecast annual customer energy conservation program cost deferrals and amortizations for 2022 to 2026:

Figure 33 – Conservation program costs – forecast deferrals and amortizations 2022 – 2026

(000s)	2022A	2023F	2024F	2025F	2026F
10-Year amortization period					
Deferral	$ (5,227)	$ (6,701)	$ (6,007)	$ (5,774)	$ (5,895)
Forecast amortization	523	1,193	1,794	2,371	2,960
Historical amortization	3,186	3,040	3,110	2,974	2,699
Total amortization	**$ 3,709**	**$ 4,233**	**$ 4,903**	**$ 5,345**	**$ 5,659**

Amortization presented in the table is calculated over ten years as approved in Order No. P.U. 3 (2022). We have recalculated the amortization for each year, and it is forecast to increase in this period from $3,709,000 in 2022 to $5,659,000 in 2026F.

5.2.3. Background – Electrification cost deferral account

In Order No. P.U.3 (2022), the Board approved the establishment of the Electrification Cost Deferral Account. As defined in Order No. P.U. 3 (2022), the Electrification Cost Deferral Account consists of the following:

- Costs incurred in implementing the Customer Electrification Program Portfolio in accordance with Board orders and approved electric vehicle charging infrastructure capital costs until otherwise ordered by the Board.
- Detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, program evaluation costs and the costs to operate Company-owned charging stations.
- Costs of major studies such as pilot programs, comprehensive customer surveys and potential studies that cost greater than $100,000.
- Credits with the receipt of government funding related to electrification programs and any revenues associated with the operation of Company-owned charging stations.
- Increases (reductions) by an interest charge (credit) on the balance in the account 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. The account will not be included in the Company's calculation of rate base until otherwise ordered by the Board.
- Transfers to, and from, the proposed account will be tax-effected.
- This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred.
- Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Clause or as otherwise ordered by the Board.

Additionally, as per Order No. P.U. 3 (2022), the account will exclude electrification expenditures that are general in nature and not associated with a specific electrification program. This includes costs associated with providing electrification awareness, and general planning, research and supervision costs.

5.2.4. Review of electrification cost deferral account

The Company has forecasted electrification program costs as follows:

Figure 34 – Electrification programs costs 2022-2026P

(000s)	2022A	2023F	2024F	2025P	2026P
Program costs	$ 1,598	$ 667	$ 565	$ 523	$ 534
Capital costs	-	-	-	-	-
Interest costs	-	105	178	230	252
Revenues	-	(10)	(10)	(10)	(10)
Annual deferral	**1,598**	**762**	**733**	**743**	**776**
Non-program costs	426	149	115	161	165
Total	**$ 3,622**	**$ 1,673**	**$ 1,581**	**$ 1,647**	**$ 1,717**

The following table provides the breakdown of the program costs related to the electrification programs forecast from 2025 to 2026P, as provided by the Company:

Figure 35 – Program costs breakdown–- electrification programs 2025-2026P

(000s)	2025P	2026P
Regular labour	$ 105	$ 109
Overtime	-	-
Miscellaneous	4	4
Conservation costs	-	-
Education & training	-	-
Travel	1	1
Other company fees	325	330
Advertising	88	90
Program Costs	**$ 523**	**$ 534**

In Order No. P.U.3 (2022), the establishment of the Electrification Cost Deferral Account was approved by the Board. However, in Order No. P.U.3 (2022) the Board did not approve the Company's proposed amendments to Clause II.9 of RSA to allow amortization of costs over a ten-year period. In Order No. P.U.33 (2022), associated with the 2021 Electrification, Conservation and Demand Management Application, the Board agreed with the ten-year recovery period for deferred electrification costs as it is consistent with both current utility practice and current practices for CDM initiatives. Please note that, while the Board agreed with the recovery period, there was no formal approval granted for recovery in P.U.33 (2022).

As a result, the Company has proposed that the Board approve, for costs commencing January 1, 2022, amendments to Clause II.9 of the Rate Stabilization Clause in Exhibit 13 as follows:

> *"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 the 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."

The Company has proposed recovering approved customer electrification costs through its RSA over 10 years, commencing January 1, 2025. Consistent with the recovery of CDM costs, the amortization amount will be charged to the Company's RSA annually on March 31st to be included in the annual July 1st adjustment. The Company has noted that it is appropriate to begin recovery, at the time, of the balance in the Electrification Cost Deferral Account as regulatory fairness principles support timely recovery of prudently incurred costs. As such, recovery of costs should be aligned with the timeframe of customer use of the asset. As the EV charging infrastructure has been in service since 2022 and the EV Demand Management Pilot Project is underway, the cost recovery beginning January 1, 2025 is consistent with the regulatory principle of intergenerational equity.[11] The resulting proposed deferrals and annual amortization cost has been outlined below:

Figure 36 – Electrification program costs – forecast deferrals and amortization 2022–-2026P

(000s)	2022A	2023F	2024F	2025P	2026P
10-Year amortization period					
Deferral	$ (1,598)	$ (762)	$ (733)	$ (743)	$ (776)
Forecast amortization	-	-	-	309	384

Amortization presented in the table is calculated over ten years. We have recalculated the amortization each year, and it is forecast to be $309,000 in 2025 and $384,000 in 2026.

5.2.5. Conclusion

Based upon our review of the Company's CDM Cost Deferral Account, we have noted no errors in the deferrals and forecast amortization based on an amortization period of ten years approved by the Board.

Based upon our review of the Company's Electrification Cost Deferral Account, we have noted no issues and conclude that the proposal to recover approved customer electrification costs through its RSA over 10 years appears reasonable.

[11] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-073

6. Depreciation

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 completed by Gannett Fleming on the calculation of its depreciation expense effective January 1, 2022.

6.1. Procedures

Depreciation amounts and rates incorporated in the 2025 and 2026 forecast are based upon the recommendations of the 2019 Depreciation Study. Specifically, we performed the following:

- Agreed all depreciation rates to those recommended in the depreciation study and the Company's pre-filed evidence; and
- Recalculated the Company's estimate of depreciation expense for 2025 and 2026.

6.2. Review of depreciation expense

The following table summarizes the depreciation expense for the years 2022 to 2026 under the 2019 Depreciation Study:

Figure 37 – Depreciation expense 2022-2026

(000s)	2022A	2023F	2023TY	2024E	2025P	2026P
Depreciation expense per exhibit 3	$ 70,662	$ 74,869	$ 74,458	$ 79,557	$ 83,143	$86,691
Year over year change ($)	NA	4,207	3,796	5,099	3,586	3,548
Year over year change (%)	NA	5.95%	5.37%	6.81%	4.51%	4.27%

The Company provided the following breakdown of the increase in depreciation expense in relation to asset class:

Figure 38 – Depreciation expense by asset class 2023TY to 2026E[12]

(000s)	2023TY	2024E	2025E	2026E	2024E vs. 2023TY	2025E vs. 2024E	2026E vs. 2025E
Steam	$ -	$ (7)	$ -	$ -	$ (7)	$ 7	$ -
Hydro	5,583	5,686	5,833	5,968	103	147	135
Diesel	159	167	165	163	8	(2)	(2)
Gas	1,948	1,973	1,989	2,011	25	16	22
Substation	10,172	10,929	11,555	12,176	757	626	621
Transmission	6,013	6,606	7,105	7,565	593	499	460
Distribution	37,114	38,867	40,383	41,899	1,753	1,516	1,516
General property	2,145	2,127	2,156	2,208	(18)	29	52
Transportation	3,507	4,138	4,529	4,867	631	391	338
Communications	335	351	362	368	16	11	6
Software	4,462	4,708	5,059	5,419	246	351	360
Hardware	2,090	2,246	2,241	2,281	156	(5)	40
CIS project	930	1,766	1,766	1,766	836	-	-
Total	**$ 74,458**	**$ 79,557**	**$ 83,143**	**$ 86,691**	**$ 5,099**	**$ 3,586**	**$ 3,548**

[12] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-055

The increase in annual depreciation expense for the years 2022 to 2026 is the result of the Company's annual capital expenditures. Depreciation expense increased by approximately $5.1 million in 2024 existing compared to the 2023 test year, and further increases by approximately $3.6 million in 2025 existing, and increases again in 2026 existing by approximately $3.5 million.

The following table summarizes existing vs proposed depreciation for 2025 and 2026:

Figure 39 – Depreciation costs 2025 and 2026

Proposed vs. Existing (000s)	2025F	2026F
Existing depreciation	$ 83,143	$ 86,691
Changes	-	-
Proposed	**$ 83,143**	**$ 86,691**

There is no difference between existing and proposed depreciation costs for 2025 and 2026 as all rates are based upon the 2019 Depreciation Study. Consistent with the Company's past practice, depreciation rates are typically reviewed every four to five years, the next depreciation study is expected to be completed in 2025 based on plant in service as of December 31, 2024.

6.3. Conclusion

Based on our review, we conclude that the depreciation rates used to calculate the proposed forecast for 2025 and 2026 agree to those recommended in the 2019 Depreciation Study and the Company's pre-filed evidence. We have recalculated the depreciation expense for 2025 and 2026 without identifying any material errors and conclude that the depreciation expense is calculated in accordance with the rates prescribed in the 2019 Depreciation Study.

7. Income taxes

Our review of income tax expense included a recalculation of income taxes based on substantively enacted corporate income tax rates for Federal and Provincial jurisdictions and an assessment of reasonableness based on forecast income and substantively enacted rates for 2022 and 2023 actuals, the 2024 – 2026 forecast and proposed forecast for 2025 and 2026.

Figure 40 – Income tax expense 2022-2026

(000s)	Actual 2022	Forecast 2023	Expected 2024	Expected 2025	Expected 2026	Proposed 2025	Proposed 2026
Income before tax	$ 67,412	$ 67,513	$ 73,568	$ 65,747	$ 59,421	$ 90,513	$ 91,192
Income taxes	19,498	20,020	22,399	20,037	18,010	27,466	27,541
Effective income tax rate (%)	**28.92%**	**29.65%**	**30.45%**	**30.48%**	**30.31%**	**30.34%**	**30.20%**
Statutory income tax rate (%)	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**

The income tax figure presented above is after adjustment for non-regulated expenses. The Company's effective income tax rate is comparable to the statutory income tax rate in effect at the time of the Application for both the existing and proposed forecast.

7.1. Conclusion

Based upon our analysis, income tax expense for forecast 2024 and proposed 2025 and 2026 appear consistent with substantively enacted corporate income tax rates and forecast increases in net income.

8. Return on rate base

8.1. Background

Rate base represents the investments made by the Company in assets required to provide services to its customers. It is a core component in determining the Company's revenue requirement and contains the following related components and considerations, all of which we will review in this section of our report:

- Average rate base ($)
- Rate of return on average rate base (%)
- Return on average rate base ($)
- Average rate base vs. invested capital
- Capital structure
- Average common equity and return on average common equity

8.2. Procedures

Our procedures with respect to verifying the return on rate base are directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company within the various components of rate base as listed above. Specifically, the procedures which we performed included the following:

- agreed the methodology used to the Public Utilities Act and relevant Board Orders to ensure it is in accordance with established policy and procedure;
- agreed all carry-forward data to supporting documentation;
- agreed forecast data to supporting documentation to ensure it is internally consistent with pre-filed evidence and other areas of the forecast;
- checked the clerical accuracy and year over year continuity of the various components of rate base and capital structure;
- recalculated the various components of rate base and capital structure;
- compared WACC and the rate of return on rate base, noting any discrepancies;
- compared average rate base and average invested capital, inquiring of any discrepancies;
- reviewed the Company's reconciliation of average rate base to average invested capital, assessing the reconciling items for consistency with historically established practice and relevant Board Orders; and,
- assessed the Company's average forecast and proposed common equity in comparison to historical results.

8.3. Average rate base vs. invested capital

8.3.1. History – the transition to the Asset Rate Base Method

The Company utilizes the Asset Rate Base Method of calculating the return on rate base. In the past, the Company transitioned from the Invested Capital Method to the Asset Rate Base Method ("ARBM").

In Order No. P.U. 19 (2003), the Board's orders pertaining to rate base in the 2003 General Rate Application noted:

> *"Newfoundland Power shall move toward the adoption of the Asset Rate Base Method for determining rate base and beginning in 2003 shall incorporate the average deferred charges, as set out in its Application, to the average rate base"*
>
> *"Newfoundland Power shall calculate and file a revised average rate base and return on rate base for 2003 and 2004, based on its proposals in this Application, incorporating the changes set out in this Decision and Order, which include:*
>
> - *A return on regulated common equity of 9.75% is to be used for calculating the weighted average cost of capital for the 2003 and 2004 test years and*
> - *The move to the Asset Rate Base Method of determining rate base"*
>
> *"Newfoundland Power shall file no later than its next general rate application a report on including in rate base the remaining reconciling items between rate base and invested capital as described in this Decision and Order."*[13]

As a part of the Newfoundland Power 2006 Capital Budget Application (the "NP 2006 CBA"), the Company filed "A Report on the Asset Rate Base Methodology" dated June 2005 [14] (the "2005 ARBM Report"). This report noted that the transition to ARBM began in 2003 with the Company including average deferred charges in the computation of average rate base as required by Order No. P.U. 19 (2003). Including deferred charges in rate base brought the Company much closer to the full implementation of the ARBM. However, at that point in time several reconciling items between rate base and invested capital remained.

The reconciling items assessed throughout the 2005 ARBM Report included the following:

1. Plant (primarily construction work in progress or "CWIP")
2. Material and supplies variance (actual vs. allowance)
3. Working capital (actual vs. allowance)
4. Corporate income tax deposit
5. Common equity (book vs. regulated)

In the 2005 ARBM Report, the Company indicated that moving to the ARBM would remove complications in converting the cost of capital to a return on rate base. The Company also noted that with the transition to the ARBM, there is no regulatory justification to change the way that rate base is calculated to further accommodate reconciling items. According to the Company,

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[13] Order No. P.U.3 (2022)

[14] A Report on the Asset Rate Base Methodology (filed in compliance with Order No. P.U.19 (2003)), June 2005 – Newfoundland Power Inc.

after implementing the ARBM the reconciliation of the five items identified above would no longer be required. However, we noted that further commentary was provided by the Company on these reconciling items as part of the 2008 General Rate Application which has been summarized below. In Order No. P.U. 30 (2005) the Board provided various decisions pertaining to the NP 2006 CBA but does not specifically address the reconciling items discussed above.

In May of 2007, Newfoundland Power filed "A Report on the Implementation of the Asset Rate Base Method (the "2007 ARBM Report") as part of the Company's 2008 General Rate Application ("2008 GRA"). This report raises the issue of the reconciling items between invested capital and rate base by noting the following:

> *"Newfoundland Power excludes assets from its rate base, such as construction work in progress ""CWI""), if they are not yet used and useful in the provision of service. However, CWIP, because it exists, had to be financed and is therefore reflected in the Company's invested capital. Although rate base and invested capital would differ with respect to CWIP, the return should be the same under both the ARBM and invested capital method.*
>
> *Differences between invested capital and rate base also arise due to differences in how rate base and invested capital items are calculated. These differences exist with respect to working capital and materials and supplies inventory.*
>
> *Working capital and materials and supplies inventory are typically reflected in invested capital at the average of their opening and year-end amounts. However, working capital is usually included in rate base through a cash working capital allowance that reflects average daily working capital requirements. Materials and supplies inventory is usually included in rate base through a materials and supplies allowance that reflects monthly averages.*
>
> *For Newfoundland Power, differences between average invested capital and average rate base related to CWIP, the cash working capital allowance and the materials and supplies allowance will continue to exist under the ARBM. The proposals in this report serve to update the calculations underlying these Reconciling Items.*
>
> *Other differences between the Company's average invested capital and average rate base are related to other assets and liabilities, which are (i) customer finance program receivables, (ii) customer security deposits (iii) the accrued pension liability (iv) the accrued other post-employment benefits ""OPEB"") liability and (v) the municipal tax liability. These differences exist because Newfoundland Power has not yet completed its transition to the ARBM. The proposals in this report serve to eliminate these Reconciling Items."* [15]

In addition to the changes to the reconciling items noted above, Newfoundland Power's 2008 GRA, dated May 10, 2007, proposed changes to the automatic adjustment formula ("AAF") in relation to the ARBM. Specifically, the Company indicated that:

> *"As a result of Newfoundland Power's completion of the transition to the ARBM of calculating rate base, the arithmetic operation of the Formula will require modification."* [16]

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[15] A Report on the Implementation of the Asset Rate Base Method, May 2007 – Newfoundland Power Inc.
[16] Newfoundland Power Inc. 2008 General Rate Application, May 10, 2007, Vol. 1, Section 3

Footnote 51 to the 2008 GRA included the existing AAF as follows:

$$\textbf{\textit{Rate of Return on Rate Base (\%) =}} \left[\frac{Invested\ capital}{Rate\ base} \times WACC\right] + \left[\frac{Z}{Rate\ base}\right]$$

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

- a) *Amortization of Capital Stock Issue Expenses (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation)*
- b) *Interest on Customer Deposits (Recognized in the weighted average cost of capital calculation but not the rate of return on rate base calculation)*
- c) *Interest Charged to Construction (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation)"* [17]

Newfoundland Power proposed that the appropriate arithmetic expression of the AAF following the transition to the ARBM be modified as follows:

Return on Rate Base ($) = [Rate Base[1] x WACC[2]]

Whereas:

1*–- rate base equals the most recent test year average rate base.*

2*–- weighted average cost of capital is derived from the capital structure approved in the most recent GRA, cost of debt is based on the most recent GRA, and the cost of equity is adjusted annually based on the calculation of a risk free rate.*

The above change was proposed as continued use of the invested capital Z factor as shown in the previous Formula was not required following the transition to the ARBM. [18]

In Order No. P.U.32 (2007) the Board then addresses the matters raised as a part of the 2008 GRA as follows:

> *"The Settlement Agreement states: the parties agreed with NP's implementation of the Asset Rate Base method as set forth in the Application [2008 GRA]".*[19]

Therefore, as part of the 2008 GRA we understand that the Board approved the transition to the ARBM in Order No. P.U. 32 (2007).

Furthermore, Order No. P.U. 32 (2007) also notes:

> *"The Settlement Agreement states: "The Automatic Adjustment Formula, reflecting the adoption of the Asset Rate Base Method as proposed in the Application, should operate in accordance with the existing methodology used by the Board to set rates for not more than three (3) years following the 2008 Test Year."* [20]

[17] Newfoundland Power Inc. 2008 General Rate Application, May 10, 2007, Vol. 1, Section 3
[18] Newfoundland Power Inc. 2008 General Rate Application, May 10, 2007, Vol. 1, Section 3
[19] Order No. P.U.32 (2007)
[20] Order No. P.U.32 (2007)

On March 12, 2010, the Company submitted an application pertaining to the 2011-2012 risk free rate of return included in the AAF. In connection with this Application the Board issued Order No. P.U. 12 (2010) which states:

> *"The risk free rate used to calculate the forecast cost of equity for use in the Automatic Adjustment Formula to establish Newfoundland Power's annual rate of return on rate base for 2011 and 2012 shall be determined by adding: (a) the average of the 3-month and 12-month forecast of 10-year Government of Canada Bonds as published by Consensus Forecasts in the preceding November; and (b) the average observed spread between 10-year and 30-year Government of Canada Bonds for all trading days in the preceding October."* [21]

On November 23, 2011, the Company submitted an application asking the Board to make an Order suspending the operation of the AAF to establish a rate of return on rate base for Newfoundland Power for 2012. Upon reviewing a series of evidence filed by the Company in support of this proposal, the Board stated the following decision in Order No. P.U. 25 (2011):

> *"The operation of the Formula to establish a rate of return on rate base for Newfoundland Power for 2012 is suspended."* [22]

On April 17, 2013, the Company submitted the 2013/2014 General Rate Application. Following their review, the Board issued Order No. P.U. 13 (2013) which 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. Dr. Booth and Mr. MacDonald offered opinions as to changes that could be made to the formula to account for the unusual financial conditions. Ms. McShane and Ms. Perry doubted whether the current financial conditions could be effectively addressed in the formula. The Board accepts that in the circumstances it would be difficult to conclude that any formula could be relied on to establish a fair rate of return after the test years.*
>
> *Newfoundland Power has applied for rates to be established based on two test years, 2013 and 2014. Newfoundland Power states that a three-year interval between general rate applications appears reasonable and given this timeframe its next general rate application would be filed in June 2015 for a 2016 test year. The Board agrees with Newfoundland Power that a three-year period between general rate applications is generally consistent with sound utility regulation.*
>
> *Newfoundland Power states that it prefers the certainty of setting a rate of return for a period of time. The Board notes that the experts forecast a period of relative stability in the bond markets with continued low long-term Canada bond yields and a gradual return to normal levels over the next several years. Dr. Booth suggests that the Board could set*

[21] Order No. P.U.12 (2010)
[22] Order No. P.U.25 (2011)

a rate of return for five years, though this suggestion was rejected by the Consumer Advocate.

Given the Board's reservations in relation to the use of the formula in the circumstances the Board finds that, in the interests of regulatory efficiency and certainty, it is appropriate to continue Newfoundland Power's rate of return on common equity at 8.8% for 2015. The Board will monitor economic conditions throughout the period and, in accordance with normal process, if there is a dramatic change in circumstances which suggest that the established rate of return is unfair an application can be filed by Newfoundland Power or directed by the Board. To be clear the Board is not discontinuing the use of the automatic adjustment formula and, in the absence of a further Order of the Board, it will be used to establish a fair return for Newfoundland Power following its next general rate application

The Board will not order the use of the formula to establish the rate of return after the 2013 and 2014 test years. The Board accepts that a ratemaking return on common equity of 8.8% in 2015, with a deemed common equity component of 45%, will provide Newfoundland Power the opportunity to earn a just and reasonable return on rate base that is consistent with the fair return principle and the provision of least cost reliable power." [23]

Subsequent GRA orders addressed customer rate adjustments for non-test year periods between GRAs. Order No. P.U. 3 (2022)–- Amended No 2 stated that:

"Newfoundland Power shall file an application on or before November 15, 2023 for approval of the 2024 forecast average rate base and rate of return on rate base, maintaining the common equity ratio and return on common equity accepted for rate setting in this Order."

For the period of 2013 to the date of the Application, the Company's rate of return (%) and return on rate base ($) has been set through either a GRA or a Rate of RORB Application in a consistent manner. Information pertaining to the results of these filings and the associated board orders are summarized in **Appendix B** of this report.

8.3.2. Review of Newfoundland Power's average rate base vs. invested capital

We noted that previously the WACC equaled the Company calculated rate of return on rate base. However, in the 2024 Rate of RORB Application and the 2025/2026 GRA, there was a difference between the WACC and the rate of RORB. Regarding this difference, the Company noted that:

"Under the Asset Rate Base Method ("ARBM"), differences in invested capital and rate base exist related to construction work in progress, materials and supplies, and cash working capital amounts. These reconciling items can cause differences between Newfoundland Power's WACC and its rate of return on rate base." [24]

[23] Order No. P.U. 13 (2013)
[24] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-076

The below table provides the reconciliation between average rate base and invested capital for the 2022 and 2023 test years, 2024 forecast, and the 2025/2026 existing and proposed:

Figure 41 – Average rate base vs. average invested capital

($millions)	2022TY	2023TY	2024F	2025E	2026E	2025P	2026P
	[1]	*[1]*	*[1]*	*[2]*	*[2]*	*[3]*	*[3]*
Average rate base (A)	**1,239.0**	**1,288.0**	**1,360.0**	**1,407.7**	**1,450.7**	**1,406.8**	**1,451.2**
Construction work in progress (CWIP)	21.0	16.0	8.0	4.6	7.5	4.6	7.5
Materials and supplies	2.0	2.0	4.0	3.7	3.8	2.7	2.8
Cash working capital	(24.0)	(19.0)	21.0	48.4	56.3	12.8	(23.6)
Average invested capital (B)	**1,238.0**	**1,287.0**	**1,393.0**	**1,464.4**	**1,518.3**	**1,426.9**	**1,437.9**
Difference (B-A)	(1.0)	(1.0)	33.0	56.7	67.6	20.1	(13.3)
Difference (WACC vs rate of RORB)	-	-	(0.18%)	0.24%	0.25%	0.11%	(0.07%)

[1] The 2022TY, 2023TY, and 2024F reconciliation was provided in response to our inquiry to the Company regarding the Newfoundland Power Inc. 2024 Rate of Return on Rate Base Application.

[2] The 2025E and 2026E reconciliation was provided in response to our inquiry to the Company regarding the Newfoundland Power Inc. 2025-2026 General Rate Application.

[3] The 2025P and 2026P reconciliation was provided in Response to Request for Information PUB-NP-076 of the Newfoundland Power Inc. 2025-2026 General Rate Application.

As shown above, the reconciling items largely offset each other for 2022 and 2023 test years. However, for 2024 forecast, 2025 existing, 2026 existing, 2025 proposed, and 2026 proposed, there are more notable differences. When asked to perform the reconciliation for 2025 and 2026 proposed and existing figures, the Company explained that the primary reason for the differences relates to average cash working capital. The Company provided the following summary of differences in average cash working capital for 2025 and 2026 existing and proposed:

Figure 42 – Total average cash working capital difference

($millions)	2025E	2026E	2025P	2026P
Accounts receivable, prepaids and accounts payable	(28.2)	(29.5)	(25.9)	(24.5)
2025 Energy Supply Cost Variance Account (“ESCV”) - **Note 1**	39.2	41.6	12.2	-
Rate Stabilization Account (“RSA”) excluding ESCV - **Note 1**	42.9	49.1	25.7	-
Deferral accounts and other	2.4	2.9	2.3	2.6
Rate base allowance	(7.9)	(7.8)	(1.5)	(1.7)
Total average cash working capital difference	**48.4**	**56.3**	**12.8**	**(23.6)**

Note 1 *–For the purposes of determining its 2025 and 2026 test year revenue requirements, Newfoundland Power has removed RSA balances and interest effective July 1, 2025 (i.e. the effective date of the proposed customer rate change) from its test year forecasts.[25] These adjustments serve to align average invested capital and average rate base for 2025 and 2026, as well as forecast WACC and rate of return on rate base. Similar adjustments were completed for the 2022 and 2023 test years to lessen the impact of the volatility of power supply cash flow effects on the Company’s test year*

[25] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-076

forecasts, which have occurred since the current wholesale rate was implemented in 2019.

The Company provided the following summary regarding the variances:

"Overall, the variances in each year reflect forecast working capital versus the cash working capital allowance in rate base. In the 2025 test year, the ESCV and RSA differences are driven by higher purchased power costs and in particular, variances in cash flows driven by the current wholesale rate.

Newfoundland Power has removed RSA balances and interest effective July 1, 2025 (i.e. the effective date of the proposed customer rate change). These adjustments serve to align average invested capital and average rate base for 2025 and 2026, as well as forecast WACC and rate of return on rate base. Similar adjustments were completed for the 2022 and 2023 test years to lessen the impact of the volatility of power supply cash flow effects on the Company's test year forecasts, which have occurred since the current wholesale rate was implemented in 2019.

Newfoundland Power anticipates the volatility associated with power supply costs to be significantly reduced upon implementation of a new wholesale rate." [26]

We noted that the three reconciling items which appear year-over-year are consistent in nature to the reconciling items that were outlined in the 2007 ARBM Report.

8.4. Review of return on average rate base ($)

Return on rate base ("RORB") ($) is typically calculated as average rate base multiplied by the rate of RORB, where the rate of RORB is equal to the weighted average cost of capital ("WACC") in test years. This calculation is presented below:

Figure 43 – Return on average rate base ($)

000s	2023TY	2024F	2025P	2026P
	[1]	*[2]*	*[3]*	*[3]*
Average rate base	1,287,450	1,360,058	1,406,816	1,451,200
Rate of RORB	6.39%	6.85%	7.40%	7.21%
Expected return on rate base	**82,268**	**93,164**	**104,104**	**104,632**
Return on rate base per Newfoundland Power	**82,275**	**93,126**	**104,049**	**104,667**
Difference	(7)	38	55	(35)

[1] 2023TY figures are from the Newfoundland Power Inc. 2022-2023 General Rate Application.
[2] 2024F figures are from the Newfoundland Power Inc. 2024 Rate of Return on Rate Base Application.
[3] 2025P and 2026P figures are from Exhibit 5 and Exhibit 8 of the Newfoundland Power Inc. 2025-2026 General Rate Application.

As shown above, the return on rate base calculated by multiplying average rate base by the rate of RORB did not agree to the return on rate base as presented by the Company. When we

[26] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-076

asked the Company to reconcile this difference, they noted that the above differences are due to rounding impacts only. The Company provided the following updated calculation using the unrounded rates:

Figure 44 – Return on average rate base ($)

000s	2023TY	2024F	2025P	2026P
		[1]		
Average rate base	1,287,450	1,360,058	1,406,816	1,451,200
Rate of RORB	6.3905%	6.8161%	7.3961%	7.2124%
Expected return on rate base	**82,275**	**92,703**	**104,049**	**104,667**
Return on rate base per Newfoundland Power	**82,275**	**92,703**	**104,049**	**104,667**
Difference	-	-	-	-

[1] Please note that the 2024F "Rate of RORB" and "Return on rate base per Newfoundland Power" included in the above table represents the figures after recovery per the 2024 Rate of RORB Application. Therefore, this differs from the regulated return on rate base amount for 2024 of $93,126,000.

8.5. Review of the calculation of average rate base

The following table shows a year-over-year analysis of average rate base for 2023 test year, 2023 forecast, 2024 forecast, and 2025 & 2026 existing figures:

Figure 45 – Average rate base 2023 to 2026

(000s)	2023TY *[1]*	2023F *[2]*	2024F *[2]*	2025E *[2]*	2026E *[2]*
Net plant investment	$ 1,259,423	$ 1,264,037	$ 1,334,567	$ 1,381,842	$ 1,425,802
Add:					
Defined benefit pension costs	98,201	98,264	104,719	108,876	112,167
Cost recovery deferrals					
Credit facility costs	-	96	90	59	31
Hearing costs	-	-	-	-	-
Conservation	22,536	20,223	21,473	22,010	22,242
2022 Revenue shortfall	345	344	115	-	-
2024 Revenue shortfall	-	-	2,353	4,706	4,706
2025 Revenue shortfall	-	-	-	-	-
Load research and retail rate design	-	174	513	800	902
Pension capitalization	400	400	997	1,020	672
Weather normalization reserve		-	1,198		
Demand management incentive account	-	297	350	-	-
Customer finance programs	2,202	1,443	1,421	1,435	1,450
	123,684	121,241	133,229	138,906	142,170
Deduct:					
Weather normalization reserve	-	2,091	-	-	-
Demand management incentive account					
Other post employee benefits	80,572	81,955	85,517	89,012	90,703
Customer security deposits	1,212	1,270	1,270	1,270	1,270
Accrued pension obligation	5,578	5,377	5,535	5,706	5,885
Accumulated deferred income taxes	23,912	25,045	33,177	35,249	37,782
Excess earnings amount	-	1,783	3,566	3,566	3,566
Refundable investment tax credits	-	146	283	265	247
	111,274	117,667	129,348	135,068	139,453
Average rate base before allowances	1,271,833	1,267,611	1,338,448	1,385,680	1,428,519
Cash working capital allowance	6,712	7,419	7,705	7,865	7,829
Materials and supplies allowance	8,905	14,676	13,905	14,164	14,389
Average rate base at year end	**$ 1,287,450**	**$ 1,289,706**	**$ 1,360,058**	**$ 1,407,709**	**$ 1,450,737**
Year-over-year change ($)		**$ 2,256**	**$ 70,352**	**$ 47,651**	**$ 43,028**
Year-over-year change (%)		**0.18%**	**5.45%**	**3.50%**	**3.06%**

[1] 2023TY figures are from Exhibit 6 of the *Newfoundland Power Inc. 2022-2023 General Rate Application.*

[2] 2023F, 2024F, 2025E and 2026E figures are from Exhibit 3 and Exhibit 5 of the Newfoundland Power Inc. 2025-2026 General Rate Application.

8.5.1. Net plant investment

When reviewing the net plant investment included in average rate base, we performed a year-over-year analysis as follows:

Figure 46 – Net plant investment year over year analysis

(000s)	2023TY	2023F	2024F	2025E	2026E
Net plant investment	$ 1,259,423	$ 1,264,037	$ 1,334,567	$ 1,381,842	$ 1,425,802
Year-over-year change ($) - Note 1		**$ 4,614**	**$ 70,530**	**$ 47,275**	**$ 43,960**
Year-over-year change (%) - Note 1		**0.37%**	**5.58%**	**3.54%**	**3.18%**

We asked the Company to explain the cause of the year-over -year change to which they noted that the increases in net plant investment primarily reflect the Company's capital investment less depreciation expense over the period.

Net plant investment is calculated as outlined in the table below:

Figure 47 – Net plant investment for rate base

(000s)	2022A	2023F	2024E	2025E	2026E
January 1, balance	2,104,248	2,204,500	2,328,878	2,425,867	2,527,261
Net additions	121,056	145,841	116,818	122,684	131,461
Retirements	(20,804)	(21,463)	(19,829)	(21,290)	(25,360)
December 31, balance	**2,204,500**	**2,328,878**	**2,425,867**	**2,527,261**	**2,633,362**
Less: work in progress	(26,428)	(10,666)	(5,434)	(3,769)	(11,268)
Plant investment for rate base	**2,178,072**	**2,318,212**	**2,420,433**	**2,523,492**	**2,622,094**
Accumulated depreciation	(914,827)	(961,971)	(1,015,030)	(1,072,697)	(1,128,860)
Contributions - customers	(41,620)	(42,817)	(42,968)	(43,072)	(43,128)
Contributions - government	(3,551)	(3,427)	(3,303)	(3,179)	(3,055)
Net plant investment	**1,218,074**	**1,309,997**	**1,359,132**	**1,404,544**	**1,447,051**
Average plant investment	**1,204,060**	**1,264,036**	**1,334,565**	**1,381,838**	**1,425,798**

(000s)	Ref	2024E	2025E	2026E
Net additions included in plant investment for rate base		116,818	122,684	131,461
Amount as per Appendix A of the 2024-2028 Capital Plan	[1]	115,252	122,684	131,461
Difference	[2]	**1,566**	**-**	**-**

[1]–- The 2024-2028 Capital Plan as submitted by the Company included approximately $115 million in capital expenditures for 2024, however we noted that subsequent to the application in Order No. P.U. 2 (2024) the Board approved approximately $114 million.

[2] -The difference relates to the MUN-T2 replacement approved in Order No. P.U. 14 (2023).

We understand that the forecast capital expenditures for 2025 and 2026 are as outlined in the 2024 Capital Budget Application and related Board order No. P.U. 2(2024).

8.5.2. Excess Earnings Amount

Excess earnings for 2023 are the earnings that exceeded the upper limit of the allowed range of return on rate base for 2023 of 6.59%, which is 18 basis points above the return on rate base approved in 2023 in Order No. P.U. 3 (2022). The disposition of any balance in the account is determined by the Board as included in the account definition.

In the 2025/2026 GRA, Newfoundland Power forecasted excess earnings for 2023 in the amount of $3.566 million (2023 balance is $3.566/2 = $1.783 million). The actual amount was $3.714 million and was transferred to a regulatory liability account on December 31, 2023. As a result, the Excess Earnings Amount is a regulatory liability of $3.566 million in proposed average rate base for 2025 and 2026.

In response to PUB-NP-007 from the 2024 RRORB Application, the Company provided two options for the disposition of the balance in the Excess Earnings Account[27]:

(i) using the balance to partially offset the proposed July 1, 2024 rate increase through a transfer to the Company's RSA at March 31, 2024, which the Company estimates would reduce the July 1st 2024 proposed customer rate increase by 0.6%; or

(ii) using the balance to offset the 2024 revenue shortfall amount of $6.7 million to be recovered as part of its 2025/2026 GRA, which the Company estimates would reduce the July 1, 2025 customer rates by 0.2%.

In the 2016/2017 GRA compliance application the excess earnings from 2013 in the amount of $68,000 (before tax) was used to reduce the 2016 revenue requirement. This treatment is consistent with option (ii) above.

The Company has not included any proposal for the disposition of the excess earnings in the 2025/2026 GRA.

[27] Newfoundland Power Inc. 2024 Rate of Return on Rate Base Application – Response to request for information PUB-NP-007.

The following table summarizes the change in 2025 and 2026 average rate base between existing and proposed figures as presented in Exhibit 3 and Exhibit 5 of the Application.

Figure 48 – Average rate base 2025 and 2026

	2025				2026			
(000s)	**Existing**	**Impact**	**Ref.**	**Proposed**	**Existing**	**Impact**	**Ref.**	**Proposed**
Net plant investment	$ 1,381,842	$ -		$ 1,381,842	$ 1,425,802	$ -		$ 1,425,802
Add:								
Defined benefit pension costs	108,876	-		108,876	112,167	-		112,167
Cost recovery deferrals								
Credit facility costs	59	(22)	(1)	37	31	(31)	(1)	-
Hearing costs	-	280	(2)	280	-	420	(2)	420
Conservation	22,010	-		22,010	22,242	-		22,242
2022 Revenue shortfall	-	-		-	-	-		-
2024 Revenue shortfall	4,706	(471)	(3)	4,235	4,706	(1,883)	(3)	2,823
2025 Revenue shortfall	-	4,693	(4)	4,693	-	7,040	(4)	7,040
Load research and retail rate design	800			800	902	-		902
Pension capitalization	1,020	-		1,020	672	-		672
Customer finance programs	1,435	-		1,435	1,450	-		1,450
	138,906	4,480		143,386	142,170	5,546		147,716
Deduct:								
Other post employee 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 amount	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	4,480		1,390,160	1,428,519	5,546		1,434,065
Cash working capital allowance	7,865	(6,390)	(5)	1,475	7,829	(6,116)	(5)	1,713
Materials and supplies allowance	14,164	1,017	(6)	15,181	14,389	1,033	(6)	15,422
Average rate base at year end	**$ 1,407,709**	**$ (893)**		**$ 1,406,816**	**$ 1,450,737**	**$ 463**		**$ 1,451,200**

(1) **Credit facility costs** – the Company noted that these are costs related to amendments to the Company's Committed Credit Facility normally for a 1-year extension. In a test year, these costs are included as a component of Invested Capital and reflected in customer rates. Between test years, these costs are reflected in average rate base until they can be recovered through inclusion in invested capital during the next general rate application, in this case, the 2025/2026 General Rate Application.

(2) **Hearing costs** – the Company noted that they estimate that $1 million in costs will be incurred and billed to the Company by the Consumer Advocate and the Board. Consistent with prior general rate applications, the Company is proposing to recover these costs from customers over a 30-month period beginning on July 1, 2025. Consistent with prior general rate applications, the unrecovered portion of these costs are included in average rate base.

(3) **2024 revenue shortfall** – the Company noted that they are proposing to amortize the 2024 Revenue shortfall of $6.7 million ($4.7 million after-tax) over a 30-month period beginning on July 1, 2025 and ending on December 31, 2027 as included in the Company's 2024 Rate of RORB Application. The highlighted differences reflect the proposed average after-tax amortizations in 2025 and 2026. The monthly amortization is approximately $224,000 ($156,800 after tax).

(4) **2025 revenue shortfall**–- the Company noted that they are proposing to amortize the 2025 Revenue shortfall of $16.8 million ($11.7 million after-tax) over a 30-month period beginning on July 1, 2025 and ending on December 31, 2027. The highlighted differences reflect the proposed average after-tax amortizations in 2025 and 2026. The monthly amortization is approximately $559,000 ($391,300 after tax).

(5) **Cash working capital allowance** – The Company noted that the change reflects the revised cash working capital factors as proposed in the Company's 2025 and 2026 Rate Base Allowances Report. The 2025 and 2026 cash working capital allowance factor was reduced from 1.20% (based on 2023 Test Year CWC Allowance factor) to 0.466% in 2025 and 0.562% in 2026.

(6) **Materials and supplies allowance** – the Company noted that the change reflects the revised materials and supplies expansion factor as proposed in the Company's 2025 and 2026 Rate Base Allowances Report. The 2025 and 2026 expansion factor was reduced from 19.08% (based on 2023 Test Year CWC Allowance factor) to 13.27% in 2025 and 2026, based on a review of actual inventory balances at December 31, 2022.

8.6. Review of capital structure

In the 2025/2026 GRA, the Company is proposing to maintain a capital structure which is consistent with the structure established by Order No.'s P.U. 16 (1998-99), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), P.U. 13 (2013), P.U. 18 (2016), P.U. 2 (2019), and P.U. 3 (2022). Newfoundland Power's targeted capital structure consists of 45% common equity for ratemaking purposes.

Based on our recalculations of the components of the capital structure, the Company's projected average capital structure for 2022 through 2026 is as follows:

Figure 49 – Capital structure 2022-2026

(%)	2022A	2023F	2024F	2025F	2026F	2025P	2026P
Debt	55.29%	56.40%	56.55%	56.43%	57.22%	55.14%	55.04%
Common Equity	44.71%	43.60%	43.45%	43.57%	42.78%	44.86%	44.96%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The above table shows that the Company's forecast average common equity for 2023 to 2026 is below the 45% maximum approved by the Board. The debt portion of the cost of capital for 2025 and 2026 proposed is 5.21% and 5.18% respectively. We recalculated the debt portion of the cost of capital using the average debt, included in the average capital structure above, and the finance charges presented in Exhibit 5 (Page 7 of 9) of the Application.

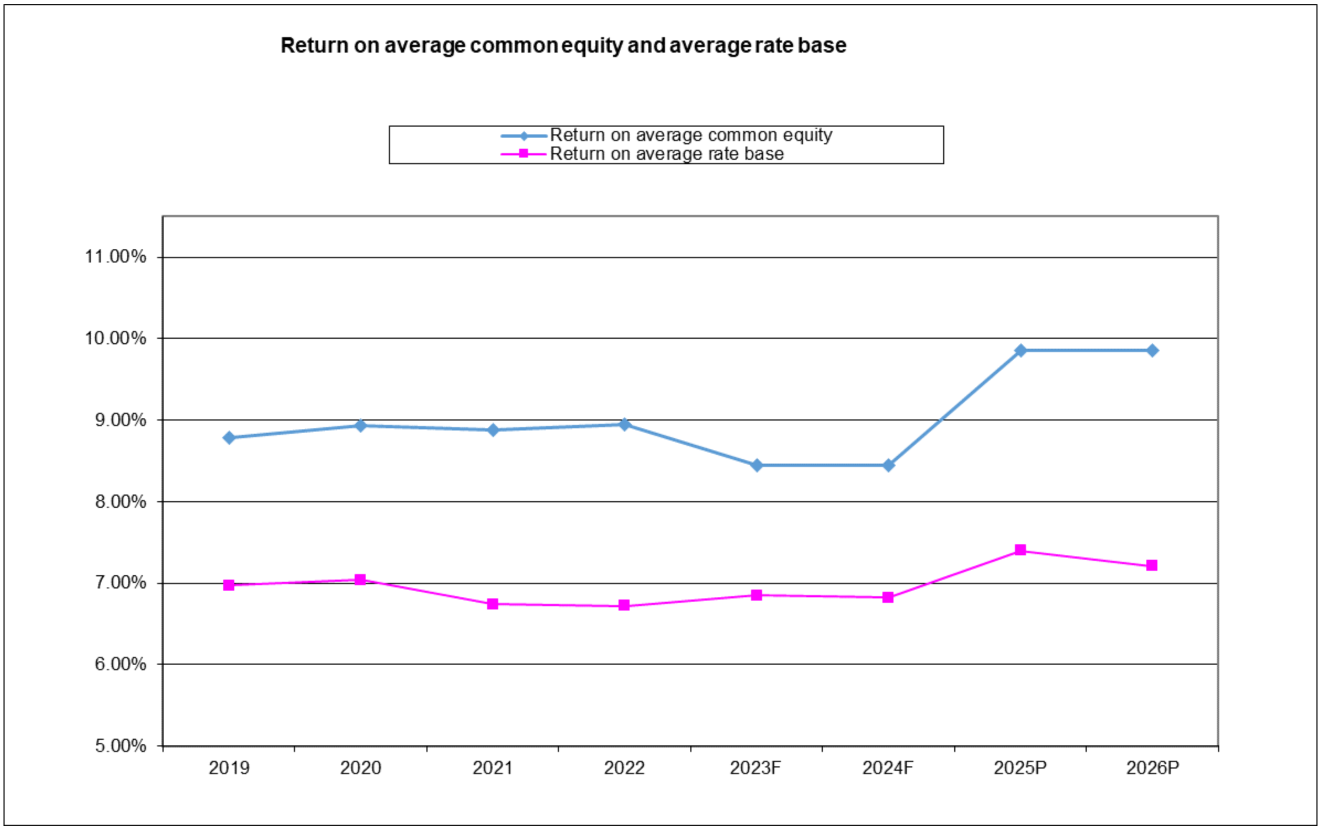
8.7. Review of return on average common equity

Expert evidence filed by Mr. James Coyne with the 2025/2026 GRA indicates what he believes to be a fair return. Newfoundland Power has noted that based on this expert evidence, it is targeting a 2025 and 2026 return on equity of 9.85%.

The following is a comparison of the actual return on average common equity from 2019 to 2022, forecast for 2023 and 2024, and proposed 2025 and 2026 with the actual return on average rate base for 2019 to proposed 2026.

Figure 50 – Average common equity vs. return on average rate base 2019-2026

	2019	2020	2021	2022	2023F	2024F	2025P	2026P
Return on average common equity	8.79%	8.93%	8.88%	8.95%	8.44%	8.44%	9.85%	9.85%
Return on average rate base	6.97%	7.04%	6.74%	6.72%	6.85%	6.82%	7.40%	7.21%
Spread between actual returns	1.82%	1.89%	2.14%	2.23%	1.59%	1.62%	2.45%	2.64%



As demonstrated by the graph above, the proposed 2025 and 2026 return on average rate base results in an increase in the spread between the return on average common equity and return on average rate base as compared to the previous years shown.

8.8. Review of the rate of return on average rate base (%)

Since 2013, the Company's rate of return on rate base (%) and return on rate base ($) has been set through either a GRA or a specific Rate of RORB ("RRORB") application. Test year rate of return on rate base and return on rate base are set by a GRA while non-test years go through the Rate of RORB Application process. In response to NLH-NP-005 of the 2024 Rate of Return on Rate Base Application [28], the Company provided information pertaining to the results of the filings and the associated Board Orders for 2013-2023. We have summarized this information as well as the 2024 forecast, and 2025/2026 proposed figures for the proposed range and rate of RORB in **Appendix B**.

[28] Newfoundland Power Inc. 2024 Rate of Return on Rate Base Application – Response to request for Information NLH-NP-005

Upon review of the historical results outlined in **Appendix B,** we noted that for the prior RRORB years (2015, 2018, 2021), the forecasted rate of RORB was within the set range and as a result, these RRORB years did not result in an increase to customer rates. However, given the 2024 forecasted rate of RORB before recovery is presented as 6.21% [29], this is below the range of rate of RORB proposed in the 2024 Rate of RORB Application of 6.67% to 7.03%. As a result, the 2024 Rate of RORB Application proposes an increase to customer rates, unlike previous years.

8.9. Automatic Adjustment Formula

In Order No. P.U. 16 (1998-99) and Order No. P.U. 36 (1998-99) the Board ordered the use of the automatic adjustment formula to set an appropriate rate of return on rate base for the Company on an annual basis ("the Formula").

Under use of the Formula, if the Asset Rate Base Method ("ARBM") is followed, the return on rate base should be equal to the rate base multiplied by the weighted average cost of capital. When asked why Newfoundland Power is not proposing to apply this formula in the determination of rate base for the 2025-2026 GRA, the Company responded with the following:

> *"Under the ARBM, rate base is determined so that it represents the invested capital necessary to finance the rate base (the debt and equity investments). In this way, the Company's return on rate base could theoretically be expressed by multiplying its rate base by its WACC. However, Newfoundland Power's return on rate base has been determined by adding the Company's return on debt, return on common equity and return on preferred equity together in its general rate applications and rate of return on rate base applications since 2008."* [30]

In Order No. P.U. 25 (2011), the Board approved the suspension of the operation of the Formula to establish a rate of return on rate base and it has continued to be suspended since that point in time. Therefore, use of the Formula has not be required by the Board since then. The appropriateness of the Company's proposal to discontinue the use of the Formula has not been addressed in this report.

As shown above in **Section 8.7** of this report, return on equity for 2024 forecast is 8.44% while return on equity for 2025 and 2026 proposed is 9.85%. However, when asked to outline what the return on equity would have been using the Formula, the Company provided the following response:

> *"The Automatic Adjustment Formula (the "Formula") requires information only available in the months leading up to the year in which the adjusted return on equity ("ROE") is to apply. For example, to estimate the ROE that the Formula would calculate for 2025 would require information that would only become available in October and November of 2024."* [31]

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[29] Newfoundland Power Inc. 2024 Rate of Return on Rate Base Application – Appendix D
[30] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-076
[31] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-067

> *Had the Formula been reinstated by the Board following Newfoundland Power's 2022/2023 General Rate Application, it would have resulted in a return on equity of 9.27% for 2024."* [32]

The Company provided the following Pro Forma ("PF") ROE that would have resulted from the operation of the Formula in 2024:

Figure 51 – Automatic Adjustment Formula 2024 Pro Forma cost of equity

(%)	2024PF	Ref
3-month forecast of 10-year Government of Canada bond yield - **Note 1**	3.70%	A
12-month forecast of 10-year Government of Canada bond yield - **Note 1**	3.40%	B
Average 10-year Government of Canada bond yield	3.55%	C = (A+B)/2
Add: Average observed spread between 10-year and 30-year government bonds - **Note 2**	-0.25%	D
Forecast long Canada bond yield	3.30%	E = C + D
Long Canada bond yield - **Note 3**	2.34%	F
Change in long Canada bond yield	0.96%	G = E - F
Change in forecast cost of equity - **Note 4**	0.77%	H = G x 0.8
Cost of equity - Order No. P.U.3 (2022)	8.50%	I
Change in cost of equity	0.77%	H
2024 forecast cost of equity	**9.27%**	**J = I + H**

***Note 1** – the Company noted that yields are those reported in the Consensus Forecasts, Survey of International Economic Forecasts, October 9, 2023.*
***Note 2** – the Company noted that average observed spread for all trading days in October 2023 between 10-year and 30-year Government of Canada Bonds as reported on the Bank of Canada website.*
***Note 3** – the Company noted that average forecast 30-year Government Bond Yield for 2022 and 2023 based on Consensus Forecasts, Survey of International Economic Forecasts, April 12, 2021, Long-Term Forecasts and the average observed spread between 10-year and 30-year Government Bonds in March 2021 as reported on the Bank of Canada website.*
***Note 4** – the Company noted that the change in forecast cost of equity reflects an adjustment in the total risk premium by a factor of 0.20 as required by Orders No. P.U. 16 and P.U. 36 (1998-99).*

The appropriateness of the continuation of the Formula is linked to the proposed return on common equity and is therefore outside the scope of our report.

8.10. Conclusion

We have completed our review of the return on rate base included in the Company's proposed revenue requirement for 2025 and 2026 and can offer the following comments:

- **We reviewed the underlying support of the reconciling items between the average rate base and the average invested capital amounts and found no discrepancies.**

[32] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NLH-067

Based upon the identified procedures and our review of the Company's response, we did not note any discrepancies in the clerical accuracy of the proposed 2025 and 2026 return on average rate base calculation. The proposed average rate base accurately reflects the Company's proposals with respect to the regulatory deferral accounts and the updated calculations related to the rate base allowances.

- **We have found no exceptions or errors in the proposed capital structure. The proposed capital structure for 2025 and 2026 is consistent with the position confirmed by the Board in Order No. P.U. 3 (2022). The calculations of capital structure are consistent with Exhibit 3 (Page 6 of 9), Exhibit 5 (Page 6 of 9) and Exhibit 8 presented in the 2025/2026 GRA. It is consistent with prior practice and in accordance with the underlying expert report filed by the Company.**
- **We have reviewed how the Company has incorporated the proposed return on equity into the calculation of return on rate base and found no errors. Please note that the 2025 and 2026 proposed rate of return on equity is outside of the scope of this report.**

During our review we noted that the WACC and the rate of RORB did not agree. While we have discussed this matter with the Company, we have not fully completed our assessment of this issue prior to the report date. Our work is ongoing and any additional observations or recommendations will be communicated to the Board via a supplemental report.

9. Revenue from rates

The Company has proposed forecast revenue requirements from customer rates for 2025 of $768,770,000 and 2026 of $789,602,000.

9.1. Procedure

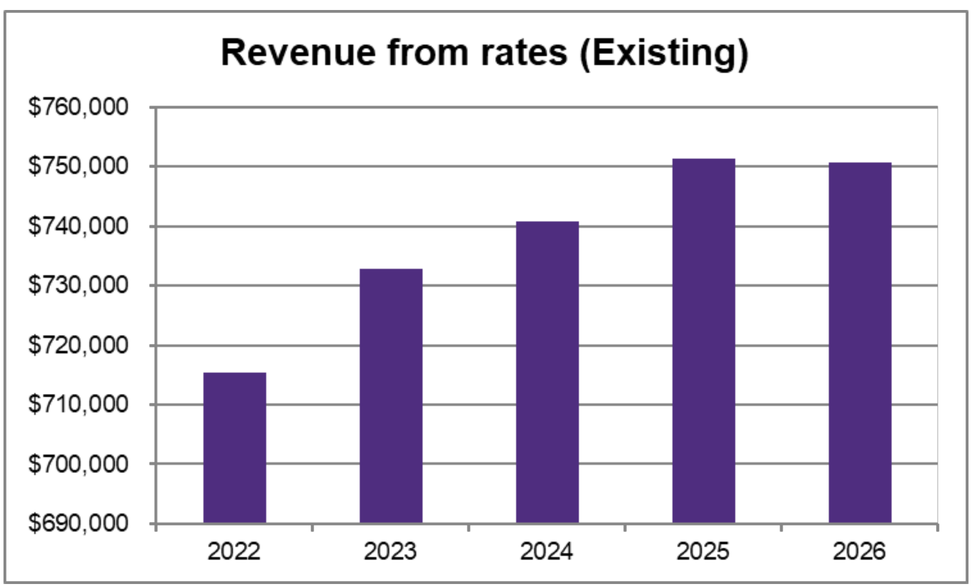
Our procedure with respect to the proposed revenue forecast included comparing revenues for the period of 2022 to 2026 to assess any significant trends.

9.2. Review of revenue from rates

We have compared the actual revenues for 2022 to the forecast revenues using existing rates for 2023 to 2026, as provided by the Company, to assess any significant trends. The Company has indicated in its Application that the revenue forecast is based on the “Customers, Energy and Demand Forecast” dated September 2023. The results of this analysis by rate class are as follows:

Figure 52 – Existing revenue from rates 2022-2026F

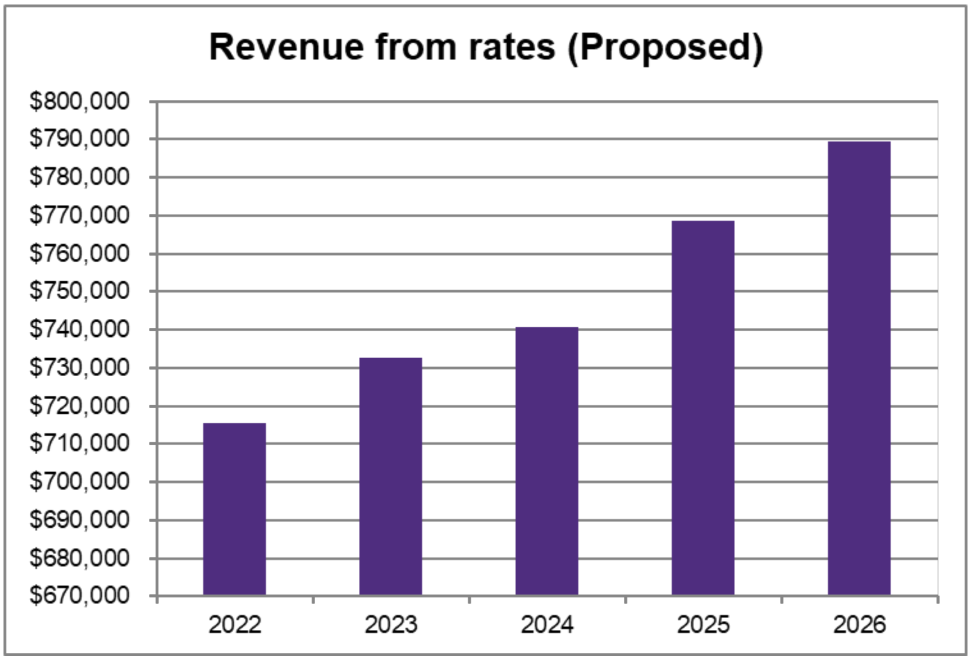
(000s)	2022A	2023F	2024F	2025F	2026F
Residential	$ 455,223	$ 467,929	$470,996	$ 471,101	$ 470,916
General service					
0-100 kw	95,983	96,974	97,959	98,904	99,218
110-1000 kva	107,955	111,185	112,375	113,537	113,424
Over 1000 kva	36,923	37,358	40,026	48,362	47,963
Streetlighting	16,725	16,598	16,492	16,427	16,226
Discounts forfeited	2,635	2,765	2,968	2,984	2,976
Revenue from rates	**$ 715,444**	**$ 732,809**	**$740,816**	**$ 751,315**	**$ 750,723**
Year over year % change		**2.43%**	**1.09%**	**1.42%**	**-0.08%**



The following summarizes the actual revenues for 2022 to the forecast revenues using proposed rates for 2025 to 2026, as provided by the Company, to assess any significant trends:

Figure 53 – Proposed revenue from rates 2022-2026P

(000s)	2022A	2023F	2024F	2025P	2026P
Residential	$ 455,223	$ 467,929	$470,996	$ 481,170	$ 493,386
General service					
0-100 kw	95,983	96,974	97,959	101,260	104,862
110-1000 kva	107,955	111,185	112,375	116,620	120,203
Over 1000 kva	36,923	37,358	40,026	49,769	50,841
Streetlighting	16,725	16,598	16,492	16,919	17,197
Discounts forfeited	2,635	2,765	2,968	3,032	3,113
Revenue from rates	**$ 715,444**	**$ 732,809**	**$740,816**	**$ 768,770**	**$ 789,602**
Year over year % change		**2.43%**	**1.09%**	**3.77%**	**2.71%**



The Company's revenues have been fluctuating by various percentages since 2022. The Company has noted the following reasons for the changes in the revenue levels from 2022 to 2026:

- The 2.43% increase in 2023 over 2022 was primarily due to increases in energy sales of 2.85% from higher new customer connections reflecting population growth and higher average service consumption.
- The 2024 forecast increase in revenues using existing rates in effect is 1.09% more than 2023 due to the increase in energy sales of 0.54%.
- The 2025 forecast increase in revenues using existing rates in effect is 1.42% over the 2024 forecast. Under the new rates proposed in this Application, the revenues for 2025 are forecast to increase 3.77% over 2024 forecast, which is primarily a result of the proposed rate increase of 5.5%.
- The 2026 forecast decrease in revenues using existing rates in effect is 0.08% compared to the 2025 forecast. Under the new rates proposed in this Application, the increase in revenues for 2026 over proposed 2025 is 2.71%, which is primarily a

result the proposed rate increase of 5.5% being enacted the entire twelve months. The proposed rates would take effect July 1, 2025.

The number of customers and the GWhs sold to these customers for 2022 and forecast 2023 to 2026 and proposed 2025 and 2026 are as follows:

Figure 54 – Customers and electricity sold 2022-2026[33]

	2022A	2023F	2024F	2025F	2026F
Customers	273,764	275,281	276,444	277,467	278,359
% Change (2022-2026)		0.55%	0.42%	0.37%	0.32%
GWh sold	5,785	5,949	5,981	6,034	6,026
% Change		2.85%	0.54%	0.88%	-0.13%

	2022A	2023F	2024F	2025P	2026P
Customers	273,764	275,281	276,444	277,467	278,359
% Change (2022-2026)		0.55%	0.42%	0.37%	0.32%
GWh sold	5,785	5,949	5,981	6,018	5,978
% Change		2.85%	0.54%	0.61%	-0.66%

The number of customers is expected to increase by an average of 0.4% per year, or 1.7% over the 2022 to 2026 year period, and GWhs sold is expected to increase by an average of 0.8% per year, or 3.4% over the same period. Further information on these trends are detailed below.

Number of customers

- As the above table indicates, from 2022 to 2023 the number of customers increased by 0.55%. This trend is forecasted to continue to increase for 2024 to 2026 forecast with an annual increase of 0.42%, 0.37%, and 0.32%, respectively.
- The Company stated that it is expecting lower customer growth over the 2024 to 2026 period in comparison to forecast 2023 growth based on the Conference Board of Canda's forecast of housing starts and completions. The Conference Board of Canda's forecast explains that higher mortgage rates, demographic trends, and a decreasing population will weaken the outlook for housing demand and residential construction.[34]
- The Company has stated that lower forecast customer growth is also expected as the Newfoundland and Labrador economy remains weak and the downward trend is forecasted to continue.[35]
- The Company has also stated that there is no elasticity effect for the number of customers shown in the table above.[36]

[33] Newfoundland Power Inc. 2025-2026 General Rate Application, December 12, 2023, Tables 1-1, 3-1 and 5-3.
[34] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-081
[35] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-003
[36] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information CA-NP-099

Energy sales

- GWhs sold by the Company increased by 2.85% from 2022 to 2023. Under existing rates, the Company has forecast an increase of 0.54% and 0.88% for 2024 and 2025, respectively, with a decrease of 0.13% for 2026.
- The Company stated that a reduction in the forecast energy sales is due to domestic heat pump installation supplementing existing electric heat as it provides a reduction in energy use due to better space heating efficiency provided by heat pumps. By 2026, the Company estimates approximately 35% of domestic all-electric customers will have a heat pump installed, which is reflected in the above with a reduction in GWh sold.[37]

In reviewing the 2023 to 2026 forecast revenues, we agreed all forecast amounts to supporting schedules provided by the Company. In addition, we calculated the average revenue forecast per customer by rate class to assess its reasonableness.

9.3. Conclusion

Based on our procedures nothing has come to our attention to indicate the forecast revenue from rates for 2023, 2024, 2025 and 2026 are unreasonable.

[37] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-093

10. Adjustments to revenue requirement

Before the revenue requirement is incorporated into the rates calculation, it is adjusted for a number of items including the following:

- The impact of other revenue;
- The impact of interest on security deposits (presented in Finance Charges);
- The impact of energy supply cost variance adjustments; and
- The impact of other transfers to/from the RSA.

10.1. Other revenue

The Company's other revenue for 2022 and forecast for 2023-2026 is as follows:

Figure 55 – Other revenue 2022-2026

(000s)	2022A	2023A	2023F	2024F	2025F	2026F
Pole attachment	$ 2,483	$ 2,579	$ 2,545	$ 2,585	$ 2,622	$ 2,660
Provisioning work	2,086	1,875	1,579	1,270	1,015	1,027
Customer account interest	1,212	1,871	1,681	1,311	1,401	1,464
Interest on RSA	(1,667)	(38)	(24)	3,213	4,295	4,758
Wheeling charges	765	675	723	719	705	704
Miscellaneous	1,241	1,015	918	928	979	1,031
Total	**$ 6,120**	**$ 7,977**	**$ 7,422**	**$ 10,026**	**$ 11,017**	**$ 11,644**
Year to year % change		**30.34%**	**21.27%**	**35.08%**	**9.88%**	**5.69%**

(000s)	2022A	2023A	2023F	2024F	2025P	2026P
Pole attachment	$ 2,483	$ 2,579	$ 2,545	$ 2,585	$ 2,622	$ 2,660
Provisioning work	2,086	1,875	1,579	1,270	1,015	1,027
Customer account interest	1,212	1,871	1,681	1,311	1,401	1,464
Interest on RSA	(1,667)	(38)	(24)	3,213	2,501	-
Wheeling charges	765	675	723	719	705	704
Miscellaneous	1,241	1,015	918	928	979	1,005
Total	**$ 6,120**	**$ 7,977**	**$ 7,422**	**$ 10,026**	**$ 9,223**	**$ 6,860**
Year to year % change		**30.34%**	**21.27%**	**35.08%**	**(8.01%)**	**(25.62%)**

The tables above indicate the following variances:

- Interest on RSA: The Company has stated that the change in the RSA interest from a credit of $1,667,000 in 2022 to a debit of $4,758,000 in the 2026 existing forecast is due largely to fluctuations in purchased power costs over that timeframe. Volatility of the Company's power supply costs have occurred since the current wholesale rate was implemented in 2019. Variances in purchased power costs are primarily recovered through the Company's Energy Supply Cost Variance Account ("ESCV" Account) which transfers to the Rate Stabilization Account at December 31 of each year. The Company has removed its RSA balances and interest effective July 1, 2025. The Company has stated that this serves to lessen the impact of the volatility of power supply cash flow effects on the Company's test year forecasts as well as better align average capital and average rate base for 2025 and 2026, similar to the adjustments in 2022 and 2023 test years.

- Miscellaneous: According to the Company, the decrease in miscellaneous charges is due to non-recurring revenue items in 2022 related to renewable energy credits, and government funded employment grants related to the Federal Student Work Placement Program. Specifically, the Company received $232,000 in 2022 related to the sale of renewable energy credits. Additionally, in 2022 employment related to the Federal Student Work Placement Program were approximately $53,000.

10.1.1. Conclusion

Based on our procedures nothing has come to our attention to indicate the forecast other revenues for 2023, 2024, 2025 and 2026 are unreasonable.

10.2. Energy supply cost variance adjustments

In Order No. P.U. 32 (2007) the Board approved the recovery, through the RSA account, of the Energy Supply Cost Variance incurred up to the end of 2010. In 2009, the Board approved its continued use.[38] This mechanism is intended to address variances in purchased power costs. Variances in purchased power costs can occur as a result of variances in energy purchased requirements, and differences between the incremental rate that the Company pays, and the average supply cost in customer rates. As noted in Figure 3 of our report, proposed energy supply cost variance adjustments in 2025 and 2026 are approximately $40.165 million and $35.495 million, respectively.

Based on the Company's proposal to not rebase power supply energy costs, we recalculated the 2025 and 2026 proposed energy supply cost variance adjustments and found no errors.

10.3. Other transfers to RSA

Existing and proposed other transfers to the RSA deducted from revenue requirement from rates are summarized in the table below.

Figure 56 – Other transfers to RSA[39]

	2025			2026		
(000s)	Existing	Changes	Proposed	Existing	Changes	Proposed
CDM amortization	$ (5,345)	$ -	$ (5,345)	$ (5,658)	$ -	$ (5,658)
PEVDA	(5,955)	5,955	-	(2,838)	2,838	-
OPEBVDA	853	(853)	-	4,239	(4,239)	-
Electrification amortization	-	(309)	(309)	-	(384)	(384)
Other transfers to RSA	**$ (10,447)**	**$ 4,793**	**$ (5,654)**	**$ (4,257)**	**$ (1,785)**	**$ (6,042)**

The changes in other transfers to RSA for the 2025 and 2026 proposed compared to existing are a result of the rebasing of the Pension Expense Variance Deferral Account ("PEVDA") and Other Post-Employment Benefits Cost Variance Deferral Account ("OPEBVDA"), and the

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[38] Order No. PU. 43(2009)

[39] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information CA-NP-045

amortization of electrification deferral costs.[40] Our findings and conclusions of both the CDM and electrification amortization are discussed in Section 5 of this report. It is important to note that both CDM and electrification amortization costs are included in operating costs and are adjusted from revenue requirement with the above adjustment. In contrast, the amortization of hearing costs included in operating costs remain in revenue requirement and are therefore included in customer rates as they are not transferred through the RSA; the Company has proposed that any difference from the estimated $1,000,000 in hearing costs and actual is rebated or collected through the RSA.

Based on our review and analysis, nothing has come to our attention to indicate that other transfers to the RSA are unreasonable.

[40]Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information CA-NP-045

11. Proposed revenue from rates

11.1. Background

The Company is proposing that the Board approve rates, tolls and charges effective for service provided on and after July 1, 2025 to provide an average increase by class in electrical rates of 5.5%, based upon:

- a forecast average rate base for 2025 of $1,406,816,000 and for 2026 of $1,451,200,000.
- a rate of return on average rate base for 2025 of 7.40% in the range of 7.22% to 7.58% and for 2026 of 7.21% in a range of 7.03% to 7.39%; and
- a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in the Application of $768,770,000 for 2025 and of $789,602,000 for 2026.

11.2. Procedures

We have reviewed the Company's proposed rates effective July 1, 2025. Specifically, the procedures we have performed include the following:

- Recalculated the revenue that results from using the revised rates, ensuring that it agrees with the revenue requirement submitted by the Company;
- Recalculated the factors used in the revenue calculations (number of customers, energy and demand usage, etc.) to those presented by the Company;
- Agreed the rates used in the revenue calculations to those in the proposed Revised Schedule of Rates, Tolls and Charges; and,
- Recalculated the percentage increase in revenue by rate class and the percentage increase in individual rates, tolls and charges.

11.3. Review of proposed revenue from rates

The following table compares July 1, 2024, rates to July 1, 2025 proposed rates by class including RSA and Municipal Tax Adjustment ("MTA"). July 1, 2024 rates are based on the 2024 Rate of Return on Rate Base Application filed by the Company on November 23, 2023. This matter is before the Board and subject to Board Order, which could change the outcome:

Figure 57 – Existing and proposed rates, tolls & charges

	PROPOSED RATES[1] July 1, 2024	PROPOSED RATES July 1, 2025	CHANGE ($)	CHANGE (%)
DOMESTIC				
Total Customers for Class (000's)	240,595	241,461	866	0.36%
DOMESTIC - RATE # 1.1				
Basic Customer Charge (Monthly)				
Not Exceeding 200 AMP service	$16.06	$17.02	$0.96	5.98%
Exceeding 200 AMP Service	$21.06	$22.02	$0.96	4.56%
Energy Charge - All Kilowatt Hours (Cents/kWh)	$0.13449	$0.14178	$0.00729	5.42%
Minimum Monthly Charge				
Not Exceeding 200 AMP service	$16.06	$17.20	$1.14	7.10%
Exceeding 200 AMP Service	$21.06	$22.02	$0.96	4.56%
Prompt Payment Discount	1.50%	1.50%	-	-
DOMESTIC - RATE # 1.1S				
Basic Customer Charge (Monthly)				
Not Exceeding 200 AMP service	$16.06	$17.02	$0.96	5.98%
Exceeding 200 AMP Service	$21.06	$22.02	$0.96	4.56%
Energy Charge - All Kilowatt Hours (Cents/kWh)				
Winter Seasonal	$0.14402	$0.15131	$0.00729	5.06%
Non-Winter Seasonal	$0.12152	$0.12881	$0.00729	6.00%
Minimum Monthly Charge				
Not Exceeding 200 AMP service	$16.06	$17.02	$0.96	5.98%
Exceeding 200 AMP Service	$21.06	$22.02	$0.96	4.56%
Prompt Payment Discount	1.50%	1.50%	-	-
G.S. 0-100 kW (110 kVA) - RATE # 2.1				
Total Customers for Class (000's)	23,352	23,453	101	0.43%
Basic Customer Charge (Monthly)				
Unmetered	$12.25	$13.59	$1.34	10.94%
Single Phase	$20.25	$21.59	$1.34	6.62%
Three Phase	$32.25	$33.59	$1.34	4.16%
Demand Charge Regular				
Winter (kW)	$9.84	$10.33	$0.49	4.98%
Other (kW)	$7.34	$7.83	$0.49	6.68%
Energy Charge - All Kilowatt Hours (Cents/kWh)				
First 3,500 kilowatt-hours	$0.13308	$0.14030	$0.00722	5.43%
All excess kilowatt-hours	$0.10304	$0.10847	$0.00543	5.27%
Maximum Monthly Charge	$0.22226 plus B.C.C.	$0.23479 plus B.C.C.	$0.01253	5.64%
Minimum Monthly Charge				
Unmetered	$12.25	$13.59	$1.34	10.94%
Single Phase	$20.25	$21.59	$1.34	6.62%
Three Phase	$32.25	$33.59	$1.34	4.16%
Prompt Payment Discount	1.50%	1.50%	-	-

[1]In the 2025/2026 GRA Application, the Company referred to July 1, 2024 as existing rates, however we noted that the rates are based upon the 2024 Rate of Return on Rate Base Application filed by the Company on November 23, 2023. This matter is before the Board and subject to Board Order, which could change the outcome.

Figure 58 – Existing and proposed rates, tolls & charges (Cont'd)

	PROPOSED RATES[1] July 1, 2024		PROPOSED RATES July 1, 2025		CHANGE ($)	CHANGE (%)
G.S. 110-1000 kVA - RATE # 2.3						
Total Customers for Class (000's)	1,273		1,273		0	0.00%
Basic Customer Charge (Monthly)	$49.64		$52.60		$2.96	5.96%
Demand Charge						
Winter (kVA)	$8.25		$8.65		$0.40	4.85%
Other (kVA)	$5.75		$6.15		$0.40	6.96%
Energy Charge (Cents/kWh)						
First 150 kWh per kVA of demand (max 50,000)	$0.11507		$0.12121		$0.00614	5.34%
All Excess kWh	$0.09518		$0.10011		$0.00493	5.18%
Maximum Monthly Charge (Cents/kWh + BCC)	$0.22260	plus B.C.C.	$0.23479	plus B.C.C.	$0.01219	5.48%
Minimum Monthly Charge	$49.64		$52.60		$2.96	5.96%
Prompt Payment Discount	1.50%		1.50%		-	-
G.S. 1000 kVA and Over - RATE # 2.4						
Total Customers for Class (000's)	59		59		-	-
Basic Customer Charge (Monthly)	$86.50		$91.66		$5.16	5.97%
Demand Charge						
Winter (kVA)	$7.91		$8.27		$0.36	4.55%
Other (kVA)	$5.41		$5.77		$0.36	6.65%
Energy Charge (Cents/kWh)						
First 75,000 kWh	$0.11139		$0.11730		$0.00591	5.31%
All Excess kWh	$0.09436		$0.09925		$0.00489	5.18%
Maximum Monthly Charge (Cents/kWh + BCC)	$0.22226	plus BCC	$0.23479	plus BCC	$0.01253	5.64%
Minimum Monthly Charge	$86.50		$91.66		$5.16	5.97%
Prompt Payment Discount	1.50%		1.50%		-	-
STREET & AREA LIGHTING RATES						
Total Customers for Class (000's)	11,165		11,221		56	0.50%
FIXTURES						
Sentinel/Standard						
High Pressure Sodium						
100W	$18.70		$19.79		$1.09	5.83%
150W	$23.46		$24.82		$1.36	5.80%
250W	$33.63		$35.57		$1.94	5.77%
400W	$47.37		$50.07		$2.70	5.70%
Light Emitting Diode						
LED 100	$16.34		$17.11		$0.77	4.71%
LED 150	$18.49		$20.38		$1.89	10.22%
LED 250	$22.45		$25.05		$2.60	11.58%
LED 400	$26.03		$29.84		$3.81	14.64%
Post Top						
High Pressure Sodium						
100W	$19.91		$21.07		$1.16	5.83%
Poles						
Wood	$6.22		$6.79		$0.57	9.16%
30' Concrete or Metal, direct buried	$8.68		$9.27		$0.59	6.80%
45' Concrete or Metal, direct buried	$14.37		$15.37		$1.00	6.96%
25' Concrete or Metal, Post Top, direct buried	$6.16		$6.47		$0.31	5.03%
Underground Wiring						
All sizes and types of fixtures	$14.64		$15.44		-	-

[1]In the Company's 2025/2026 GRA Application, they referred to July 1, 2024 as existing rates, however we noted that the rates are based upon the 2024 Rate of Return on Rate Base Application filed by the Company on November 23, 2023. This matter is before the Board and subject to Board Order, which could change the outcome.

11.4. Conclusion

Based on our procedures, we find that the revenue requirement proposed by the Company is calculated based upon the revised Schedule of Rates, Tolls and Charges effective July 1, 2025, and the factors proposed in this Application.

12. Demand management incentive ("DMI")

In Order No. 32 (2007), the Board approved the definition of the Demand Management Incentive Account as follows:

> "*This account shall be charged or credited with the amount by which the Demand Supply Cost Variance exceeds the Demand Management Incentive. The Demand Management Incentive equals ±1% of the test year wholesale demand charges*."

The Demand Management Incentive Account was approved to replace the existing Purchased Power Unit Cost Variance Reserve. This account was to provide an incentive for the Company to take initiatives to minimize peak demand and provide them with the opportunity to recover costs associated with flexibility in purchased power costs. In Order No. 43 (2009), the Board approved the continued use of the DMI account.

The Company has proposed to amend the definition of the DMI Account as follows:

> "*The 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 test year wholesale demand charges*".

12.1. Procedures

Our procedures with respect to the amendment to the DMI definition include the following:

- Reviewed the methodology of proposed amendment to the DMI definition for reasonableness and determined if this was consistent with previously approved practices and/or industry practice; and
- Reviewed DMI matters previously approved to ensure they are in accordance with decisions outlined by the Board.

12.2. Review of DMI

The change in threshold from ±1% of the test year wholesale demand charges to ± $500,000 is to take effect January 1, 2025. The Company has outlined several reasons for proposing this change. Such reasons include the following:

- Since the approval and establishment of the DMI Account, the Company's ability to reduce its purchased power demand costs has become limited.[41]

- The wholesale rate is not within the Company's control. The wholesale rate is charged by Hydro, and this wholesale rate can have impacts on the Company's demand costs.[42] The wholesale rate includes a Minimum Billing Demand which can further limit the Company's ability to control demand costs.

- In 2008, the demand rate was $4.00 per kW. This resulted in a DMI threshold of approximately $500,000 ($528,907). In 2019, the demand rate increased to $5.00 per kW, which has provided a DMI threshold of approximately $750,000 ($750,631). This equates to a 42% [(750,631 - 528,907) / 528,907] increase over a 15-year

[41] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information CA-NP-094

[42] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information CA-NP-094

period. The Company has stated there will be a risk that the demand rate may further increase when Hydro files its next general rate application.[43]

- The Company's demand management initiatives, such as those under the takeCHARGE partnership since 2009, have been reflected in the Company's test year forecasts and has shown a reduction in demand.[44]

- A ± $500,000 threshold is consistent with prior orders of the Board. For example, the Board has approved a ± $500,000 cost threshold associated with Hydro's Holyrood Conversion Rate Deferral Account, Energy Supply Cost Variance Account and Isolated Systems Supply Cost Variance in Board Order No. P.U.49 (2016).[45] The Board maintained two ± $500,000 cost thresholds for Hydro's supply costs in Board Order No. P.U.4(2022).

- The Company and Nova Scotia Power Inc. ("Nova Scotia Power") are the only Canadian investor-owned utilities that has a threshold associated with its supply costs. Nova Scotia Power, under its Fuel Adjustment Mechanism, has an incentive threshold for its fuel variance costs, such that 90% of any savings/increases in fuel costs are credited or charged to customers, up to $50 million.[46] Both the Company and Nova Scotia Power have more risk with recovery in purchased power costs compared to other Canadian investor-owned electric utilities as incentive threshold are less common and are only implemented by these two utilities.[47]

The ± $500,000 is consistent with the threshold level associated with the DMI Account when it was first established by the Board in Order No. P.U.32 (2007).[48] As shown in the table below, the years 2008 – 2015 were consistent with approximately a $500,000 threshold, with threshold amounts increasing thereafter. Thresholds in the table below have all been calculated at ±1% of the test year wholesale demand charges, as approved in Order No. P.U.22(2007).

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[43] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information CA-NP-094

[44] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-073 and NLH-NP-074

[45] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023, page 3-54 footnote 148

[46] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023, page 3-54 footnote 147

[47] Newfoundland Power Inc. 2025-2026 General Rate Application, Volume 2 Cost of Capital Report, December 2023, page 72.

[48] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-075

The following table was provided by the Company to demonstrate the DMI threshold from 2008-2023:

Figure 59 – DMI thresholds 2008 - 2023[49]

DMI Thresholds 2008-2023	
Year	**DMI Threshold**
2008	528,907
2009	528,907
2010	545,208
2011	545,208
2012	545,208
2013	582,187
2014	593,990
2015	593,990
2016	660,706
2017	728,010
2018	728,010
2019	758,213
2020	754,555
2021	754,555
2022	750,631
2023	750,631

If the Company's proposal is not approved by the Board, the current threshold of ±1% of test year wholesale demand charges would change based on 2025 and 2026 test year demand costs. As such, according to the Company, the DMI threshold would be approximately $808,000 and $801,000 in 2025 and 2026, respectively.[50] These thresholds are significantly higher than the DMI thresholds when the DMI Account was first approved, as noted in the table above.

The following table presents a summary of the activity in the DMI account from 2008 – 2023:

Figure 60 – DMI account activity 2008 - 2023[51]

($millions)	2008 - 2015	2016 - 2023
Demand cost variance (savings)	(6.7)	12.3
Company cost (savings)	(2.2)	2.9
Customer cost (savings)	(4.5)	9.4

[49] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-075

[50] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information PUB-NP-074

[51] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-074

In the first eight years of the DMI Account (2008 to 2015), thresholds were consistent with approximately a $500,000 threshold, which provided demand savings of approximately $6.7 million, with $4.5 million being credited to customers. However, in the last eight years (2016 to 2023), thresholds have increased much higher, which provided demand costs totaling $12.3 million, and $9.4 million being charged to customers. Higher demand cost variances in the period of 2016-2023 is reflective of the Company's limited ability to reduce its purchased power demand costs.[52]

The Company provided information pertaining to the proposed change in threshold of the DMI account from ±1% of the test year wholesale demand charges to ± $500,000 in 2025 and 2026. This information is summarized in the following table:

Figure 61 – Proposed vs test year wholesale demand charges

Deadband	2025	2026
TY forecast:		
Native peak (kW)	1,476,259	1,464,911
Generation credit	130,054	130,054
Billing demand	1,346,205	1,334,857
Minimum	1,251,052	1,251,052
Dead band (kW)	13,462	13,349
@ 5.00 per kW	**$ 807,723**	**$ 800,914**
Proposed	**$ 500,000**	**$ 500,000**
Difference	**$ 307,723**	**$ 300,914**

The proposed deadband is $307,723 and $300,914 less than the deadband based upon the previous methodology if applied in 2025 and 2026, respectively.

The Company has stated that the proposal to change the threshold will have no impact on the Company's demand management incentives, such as its peak day activities, including voltage management and customer curtailment. The change in threshold will also have no effect on the Company's conservation and demand management customer programming.[53]

The Company has stated that a ± $500,000 threshold would:

- Reflect the Company's limited control in regard to options for managing peak day demand;
- Continue to provide an incentive for the Company to reduce system demand; and

[52] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-074

[53] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-074

- Limit the risks associated with recovery of demand costs due to factors outside the Company's control, such as risk of an increase in the wholesale rate.[54]

12.3. Conclusion

Based upon our review and analysis, nothing has come to our attention to indicate that the proposal to amend the definition of the DMI account definition to establish a threshold of ± $500,000 is unreasonable.

[54] Newfoundland Power Inc. 2025-2026 General Rate Application, December 2023 - Response to Request for Information NLH-NP-075

Appendix A - Glossary of terms

2005 ARBM Report	Newfoundland Power Inc. "A Report on the Asset Rate Base Methodology". Dated June 2005
2007 ARBM Report	Newfoundland Power Inc. "A Report on the Implementation of the Asset Rate Base Method". Dated May 2007
2008 GRA	2008 General Rate Application as filed by Newfoundland Power Inc.
2019 depreciation study	Gannet Fleming 2019 Depreciation Study as filed in Volume 3, Expert Evidence, as part of the Company's 2022/2023 GRA.
2022 Annual Review	Board of Commissioners of Public Utilities Financial Consultants Report - 2022 Annual Financial Review of Newfoundland Power Inc.
2025/2026 GRA, Application	2025/2026 General Rate Application as filed by Newfoundland Power Inc. dated December 12, 2023
A	Actual
AAF	Automatic Adjustment Formula
ARBM	Asset Rate Base Method
Board	Board of Commissioners of Public Utilities
CBOC	Conference Board of Canada
CDM	Conservation and Demand Management
CED	Customer, Energy and Demand
CSS	Customer Service System
Company, Newfoundland Power	Newfoundland Power Inc.
CWIP	Construction work in progress
DB Plan	Defined Benefit Pension Plan
ESCV	Energy Supply Cost Variance
F	Forecast
Fortis	Fortis Inc.
FTE	Full-time equivalent
GDP	Gross Domestic Product
GIS	Geographic Information System
GRA	General Rate Application
IFRS	International Financial Reporting Standards
Korn Ferry	Korn Ferry Limited
Korn Ferry report	Korn Ferry Limited "Executive Compensation – 2024 Estimated Market Actual Salary Median" report dated November 2, 2023
MSA	Municipal Tax Adjustment
NL Hydro, Hydro	Newfoundland and Labrador Hydro
Nova Scotia Power	Nova Scotia Power Inc.

NP 2006 CBA	Newfoundland Power 2006 Capital Budget Application
OPEBs	Other post-employment benefits
OPEBVDA	Other Post-Employment Benefits Cost Variance Deferral Account
P	Proposed
PEVDA	Pension Expense Variance Deferral Account
PF	Pro Forma
Prior GRA, 2022/2023 GRA	2022/2023 General Rate Application as filed by Newfoundland Power Inc. dated May 27, 2021
PUP	Pension uniformity plan
RORB	Return on rate base
RRORB	Rate of return on rate base
RSA	Rate Stabilization Account
SAIDI	System average interruption duration index
SERP	Supplemental employee retirement plan
STI	Short Term Incentive
TY	Test year
WACC	Weighted average cost of capital
We, us, our, Grant Thornton	Grant Thornton LLP

Appendix B – Rate of return on rate base

Range and rate of RORB	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023F	2024F	2025P	2026P
												Note 2	Note 2	Note 2
Note 1	GRA	GRA	RRORB	GRA	GRA	RRORB	GRA	GRA	RRORB	GRA	GRA	RRORB	GRA	GRA
Order No. setting approved range	P.U. 23 (2013)	P.U. 23 (2013)	P.U. 51 (2014)	P.U. 25 (2016)	P.U. 25 (2016)	P.U. 41 (2017)	P.U. 2 (2019)	P.U. 2 (2019)	P.U. 36 (2020)	P.U. 3 (2022)	P.U. 3 (2022)	N/A	N/A	N/A
Approved range of rate of RORB (%)	7.74 to 8.10	7.70 to 8.06	7.32 to 7.68	7.03 to 7.39	7.01 to 7.37	6.86 to 7.22	6.83 to 7.19	6.86 to 7.22	6.47 to 6.83	6.43 to 6.79	6.21 to 6.57	6.67 to 7.03	7.22 to 7.58	7.03 to 7.39
Midpoint of approved range (%)	7.92	7.88	7.50	7.21	7.19	7.04	7.01	7.04	6.65	6.61	6.39	6.85	7.40	7.21
Actual/forecast RORB (%)	8.11	7.83	7.48	7.31	7.22	7.13	6.97	7.04	6.74	6.72	6.85	6.85	7.40	7.21
Rate of RORB variance (%)	0.19	-0.05	-0.02	0.10	0.03	0.09	(0.04)	0.00	0.09	0.11	0.46	-	-	-
Regulated earnings														
Approved regulated earnings when setting rates ($000s)	37,332	38,716	39,786	41,010	42,638	42,072	44,250	45,632	44,426	47,233	49,202	51,169	63,047	63,651
Actual/forecast regulated earnings ($000s)	38,605	39,829	41,113	42,887	43,988	43,929	45,395	46,469	46,278	47,914	51,059	51,169	63,047	63,651
Regulated earnings variance ($000s)	1,273	1,113	1,327	1,877	1,350	1,857	1,145	837	1,852	681	1,857	-	-	-

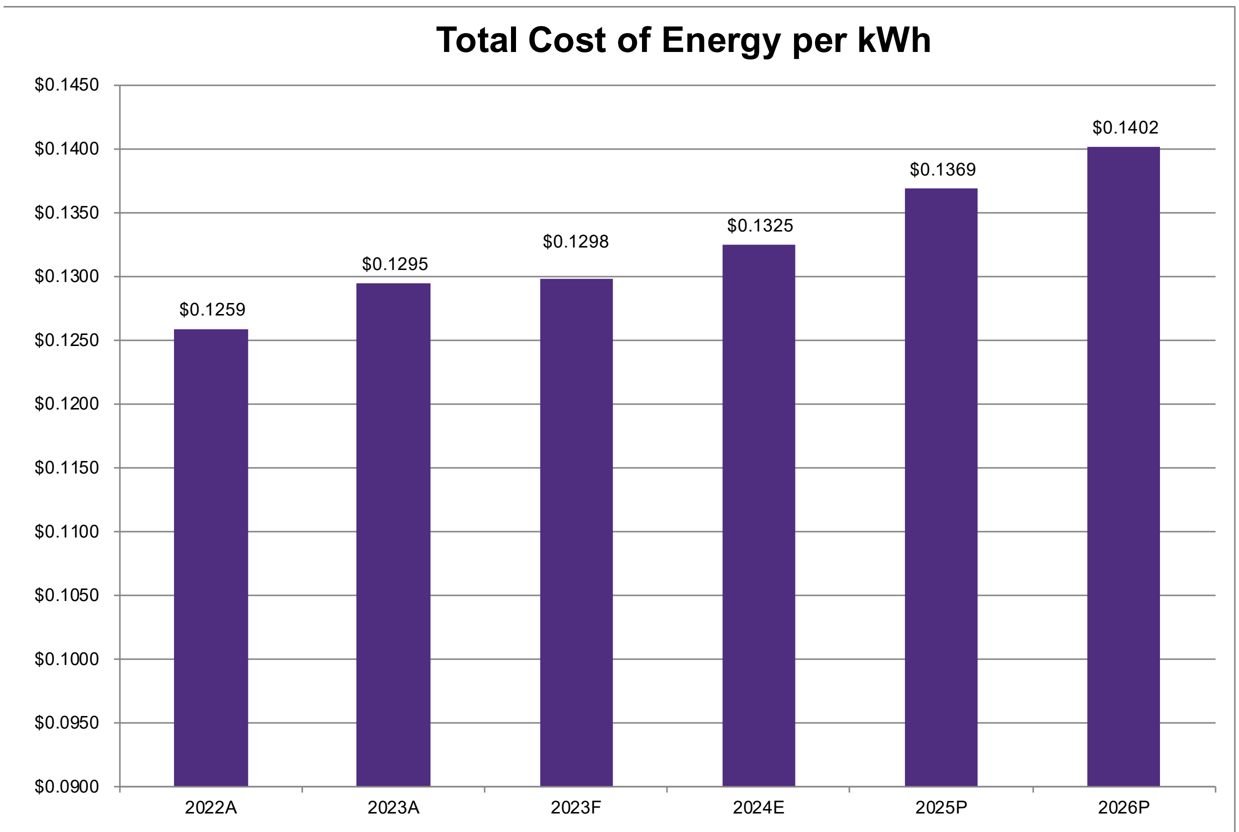
***Note 1** - For clarity we have indicated above if the rate of return on rate base (%) and return on rate base ($) was approved/proposed in the Company's General Rate Application (GRA) or a specific Rate of Return on Rate Base (RRORB) Application.*

***Note 2** - Given both the 2024 Rate of RORB Application and the 2025/2025 GRA are both pending approval from the Board, the range, rate of RORB, and regulated earnings figures have not yet been approved and are subject to change for 2024-2026.*

Appendix C – Comparison of Total Cost of Energy to kWh Sold

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation / Deferrals	Finance Charges	Income Taxes	Net Income	Total Cost of Energy	Cost per kWh
2022A	5,784,500	$ 76,521	$ 479,526	$ 70,006	$ 34,790	$ 19,498	$ 47,914	$ 728,255	$ 0.1259
2023A	5,927,900	$ 76,647	$ 511,983	$ 73,722	$ 36,842	$ 20,159	$ 48,087	$ 767,440	$ 0.1295
2023F	5,949,200	$ 76,236	$ 516,940	$ 74,053	$ 37,313	$ 20,020	$ 47,493	$ 772,055	$ 0.1298
2024E	5,981,400	$ 81,785	$ 522,821	$ 72,595	$ 41,607	$ 22,399	$ 51,169	$ 792,376	$ 0.1325
2025P	6,017,900	$ 90,025	$ 530,628	$ 71,572	$ 41,075	$ 27,466	$ 63,047	$ 823,813	$ 0.1369
2026P	5,978,300	$ 86,752	$ 522,388	$ 96,579	$ 41,089	$ 27,541	$ 63,651	$ 838,000	$ 0.1402

(1) 2022, 2023F and 2024E is based on information provided in Exhibit 3 of the supporting materials to the GRA.
(2) 2025 to 2026 is based on information provided in Exhibit 5 of the Supporting Materials to the GRA.
(3) Figures presented excludes non-regulated activity.
(4) 2023 actual results were obtained from the Company.



Appendix D – Comparison of Gross Operating Expenses to kWh Sold

		Electricity Supply		Customer Services[(2)]		General[(3)]		Totals	
Year	kWh sold	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh
2022A	5,784,500	$31,578	$0.0055	$ 17,506	$0.0030	$35,923	$0.0062	$85,007	$0.0147
2023A	5,927,900	$32,240	$0.0054	$ 17,117	$0.0029	$32,672	$0.0055	$82,029	$0.0138
2023F	5,949,200	$31,730	$0.0053	$ 18,545	$0.0031	$32,348	$0.0054	$82,623	$0.0139
2024F	5,981,400	$32,690	$0.0055	$ 17,891	$0.0030	$35,839	$0.0060	$86,420	$0.0144
2025P	6,017,900	$33,794	$0.0056	$ 17,997	$0.0030	$41,711	$0.0069	$93,502	$0.0155
2026P	5,978,300	$34,876	$0.0058	$ 18,503	$0.0031	$36,465	$0.0061	$89,844	$0.0150

(1) Based on information in Exhibit 1 of the supporting materials to the GRA except the 2023 actuals were obtained directly from the Company.
(2) Customer Services presented includes program costs prior to the allocation to the CDM and Electrification cost deferral accounts.
(3) General expenses presented include employee future benefits costs.
(4) Figures presented excludes non-regulated activity.