Grant Thornton
An instinct for growth™

Board of Commissioners of Public Utilities Financial Consultants Report

Newfoundland Power Inc.
2022-2023 General Rate Application

September 28, 2021

Table of Contents

Restrictions, qualifications and independence	2
Introduction and scope	3
System of accounts	4
Forecasting methodology and assumptions	5
2022/2023 Test year financial forecast	7
Return on rate base and equity, capital structure and interest coverage	9
Operating expenses	16
Depreciation	35
Regulatory deferral accounts	37
Conservation and demand management ("CDM") & electrification cost deferral	39
Capital expenditures	43
Non-regulated expenses	45
General expenses capitalized ("GEC")	46
Proposed forecast revenue	52
Proposed revenue from rates	56

Schedules

1 Comparison of Total Cost of Energy to kWh Sold
2 Comparison of Gross Operating Expenses to kWh Sold

Restrictions, qualifications and independence

This report is not intended for general circulation or publication nor is it to be reproduced or used for any purpose other than that outlined herein without our prior written permission in each specific instance. Notwithstanding the above, we understand that our report may be disclosed as a part of a public hearing process. Grant Thornton LLP ("GT") ("we") have given the Board of Commissioners of Public Utilities ("the Board") our consent to use our report for this purpose.

Our scope of work is as set out in our terms of reference letter, which is referenced throughout this report. The procedures undertaken in the course of our review do not constitute an audit of Newfoundland Power Inc.'s ("the Company") ("Newfoundland Power") financial information and consequently, we do not express an opinion on the financial information provided by Newfoundland Power. In preparing this report, we have relied upon information provided by Newfoundland Power.

We acknowledge that the Board is bound by the Access to Information and Protection of Privacy Act 2015 and agree that the Board may use its sole discretion in any determination of whether and, if so, in what form, this Report may be required to be released under this Act.

We reserve the right, but will be under no obligation, to review and/or revise the contents of this report considering information which becomes known to us after the date of our report.

Introduction and scope

This report to the Board presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of the Company, which was submitted to the Board on May 27, 2021 in support of its 2022/2023 General Rate Application ("GRA" or "Application").

Scope and limitations

The detailed scope of our financial review of the Company's pre-filed evidence is as follows:

Review of the following as detailed in Newfoundland Power Inc.'s 2022/2023 General Rate Application:

- Review reports and pre-filed written evidence of all Company witnesses, experts and intervenors and provide assistance and advice to the Board staff where appropriate;
- As directed by the Board staff, conduct detailed analysis and verification of financial information presented as evidence before the hearing;
- Attendance at the Hearing and give evidence upon request by the Board staff;
- Respond to any "Information Requests" or other inquiries from the Board staff or intervenors; and
- Investigate and report on any other matters which are relevant to the Hearing and fall within the general terms of reference.

Review of 2022 and 2023 financial forecast including the following:

- Examine the Company's chart of accounts to determine whether it complies with the System of Accounts prescribed by the Board;
- Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether they are reasonable and appropriate;
- Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, and return on rate base and return on common equity for the years ended December 31, 2019 and December 31, 2020 (actual), and for the years ending December 31, 2021, December 31, 2022 and December 31, 2023 (forecast);
- Verify the Company's calculation of the proposed rate of return on rate base, cost of capital and return on common equity for the years ending December 31, 2022 and December 31, 2023;
- Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2022 and 2023 test years; and
- Review the Company's calculation of estimated average rate base for the years ending December 31, 2022 and December 31, 2023.

The nature and extent of the procedures which we performed in our analysis varied for each of the items in the Terms of Reference. In general, our procedures were comprised of:

- enquiries with management, reperformance of calculations and other analytical procedures with respect to financial information in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

The financial statements of the Company for the years ended December 31, 2019 and December 31, 2020 have been audited by Deloitte LLP, Chartered Professional Accountants. The auditors have expressed their unqualified opinion on the fairness of the statements in their reports for each year. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

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.

The objective of our review of the Company's code of accounts was to ensure that it can provide sufficient and appropriate information to meet the reporting requirements of the Board. 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 31, 2021, 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 2020 Annual Report. The Company indicated that the revisions principally relate to minor wording and account number changes to improve clarity and accuracy of account descriptions. There was also the addition of two new accounts, first relating to RSA Credit for July 2020, and the second relating to Government of Newfoundland and Labrador's Interest Assistance Program. We have confirmed with the Company that no further changes have been made since this time.

Based upon our review of the Company's financial records, we have found that they are in compliance with the system of accounts prescribed by the Board. The system of accounts is comprehensive and well-structured and provides adequate flexibility for reporting purposes.

Forecasting methodology and assumptions

According to Newfoundland Power, their forecast of revenue and expenses for 2021, 2022 and 2023 is based on the expected operating and capital requirements, as well as assumptions, which reflect the best estimate of future economic conditions and events.

Our approach to this item of the terms of reference focused on three main objectives:

- to assess the methodology used by the Company for forecasting revenues and expenses;
- to assess the major assumptions disclosed in Exhibits 3 and 5 of the Application for consistency with forecast information reflected throughout the Application; and,
- to assess the incorporation of assumptions into the forecast presented by management.

Methodology

The Company has indicated that the 2022 and 2023 forecasts were developed by the Newfoundland Power's Finance Department based on a number of economic and financial inputs. The primary input is Customer, Energy and Demand ("CED") Forecast. 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 Forecast, Long-Term Forecast. 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 2022 and 2023 forecasts are provided 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 3 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.

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:

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 March 2021[1].	Applying the CBOC inputs is consistent with prior GRA.
Revenue forecast	Customer, Energy and Demand forecast dated May 2021	This basis is consistent with the prior GRA. We compared the revenue forecast to the CED forecast and found no exceptions.
Purchased power expense	NL Hydro's approved rates effective October 1, 2019	The basis of this assumption is consistent with the prior GRA period. We compared the purchase power

[1] Note – in the GRA Exhibit 5 it notes that CBOC report dated Feb 24, 2021 however, the supporting evidence filed by the Company was as of March 2021. Given the short time-lapse between the two dates we determined no further investigation was required as economic conditions would not have materially changed in that time.

Exhibit 5 - inputs and assumptions	Input or assumption	Conclusion
		expense assumptions to the NL Hydro approved rates and found no exceptions.
Employee future benefit costs	Actuarially determined factors and valuation.	See Operating Expenses.
Cost recovery deferrals	Varies by mechanism.	See Regulatory Deferral Accounts.
Depreciation rates	Based on 2019 Depreciation Study.	See Depreciation.
Operating costs	2021 reflects recent management estimates. 2022/2023 include increases of 3.00% and 2.85% respectively for labour and non-labour based on the GDP deflator.	See Operating Expenses.
Capital expenditures	2022 Capital Budget Application submitted to the Board.	We agreed the forecasted capital expenditures to the 2022 Capital Budget Application and have found no exceptions. However, at the time of this report the 2022 Capital Budget Application has not yet been approved.
Short-term interest rates	1.24% (2021), 1.36% (2022) and 1.70% (2023).	See Operating Expenses – approach is consistent with the underlying short-term interest rate forecast provided by the Company.
Long-term debt	$75 million debt issuance in 2022, forecasted to have a coupon rate of 4.25% over 30 years. Normal sinking fund provisions for existing debt.	See Operating Expenses – 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 prior GRA.
Income tax	Income tax rate of 30% for 2021 through 2023.	Consistent with the currently enacted corporate tax rates.

Other matters

The Company has noted that they are forecasting a decline in energy sales due to the penetration of heat pumps among the Company's customers. In response to CA-NP-013 the Company noted, *"The expected increased penetration of heat pumps in the market contributes to reduced energy sales and reduced peak demand in the forecast."* Furthermore, we understand that *"Newfoundland Power is currently completing a heat pump load research study. The Company has also had discussions with Hydro concerning the possible extension of the load research study into future winter seasons to better understand heat pump load behaviour during extended cold periods."*

Additionally, in response to CA-NP-013 the Company noted that there is a difference between the Newfoundland and Labrador Hydro ("NL Hydro") ("Hydro") and Newfoundland Power forecast of Newfoundland Power's peak demand. The Company has indicated that this has been under review by both utilities since 2020. At this time, the Company has noted the difference appears to relate to a difference in forecasting methodology with Newfoundland Power adopting a load factor methodology while NL Hydro has adopted a statistical regression methodology. In response to PUB-NP-109 the Company provides their position on why its methodology is appropriate instead of switching to a statistical regression methodology.

We have determined that the overall forecast methodology used by the Company is consistent with the 2019/2020 GRA. We have noted that the current forecast period includes additional assumptions regarding the market penetration of heat pumps and the economic impacts of COVID-19 through the CBOC data. The underlying assumptions have been reviewed based on supporting evidence provided by the Company and we have found no exceptions.

2022/2023 Test year financial forecast

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 of approximately $4.3 million in 2022 and $5.5 million in 2023. These requirements are based on the proposals that the Company has put forward relating to accounting for GEC, regulatory deferrals, a rate of return on average rate base of 7.19% in 2022 and 6.97% in 2023 and a rate of return on common equity of 9.8% in 2022 and 2023. The factors contributing to the increase can be summarized as follows:

Table 1: Components of 2022 Proposed Rate Change

(000's)	Existing (Including elasticity adjustment)	Changes	Proposed	Rate Change %
Return on Rate Base	$ 73,263	$ 15,910	$ 89,173	2.2%
Other Costs				
Power Supply Costs	465,610	(799)	464,811	-0.1%
Operating Costs	67,347	148	67,495	0.0%
Employee Future Benefit Costs	8,745	-	8,745	0.0%
Deferred Cost Recoveries and Amortization	-	(892)	(892)	-0.1%
Depreciation	70,424	532	70,956	0.1%
Income Taxes	15,384	6,770	22,154	1.0%
	627,510	5,759	633,269	
Total Costs and Return	700,773	21,669	722,442	
Adjustments				
Other Revenue	(4,746)	(1,178)	(5,924)	-0.2%
Interest on Security Deposits	18	-	18	0.0%
Energy Supply Cost Variance Adjustments	24,348	(19,477)	4,871	-2.7%
Demand Management Incentive Adjustments	(1,811)	1,811	-	0.3%
Other Transfers to RSA	(7,020)	977	(6,043)	0.1%
	10,789	(17,867)	(7,078)	
Elasticity Adjustment	(479)	479	-	0.1%
2022 Revenue Requirement from Rates	**711,083**	**4,281**	**715,364**	0.6%
RSA	2,462	(2)	2,460	0.0%
MTA	17,111	92	17,203	0.0%
Elasticity Adjustment	(14)	14	-	0.0%
Billed to Customers	**$ 730,642**	**$ 4,385**	**$ 735,027**	0.6%

Table 2: Components of 2023 Proposed Rate Change

(000's)	Existing (Including elasticity adjustment)	Changes	Proposed	Rate Change %
Return on Rate Base	$ 67,483	$ 22,361	$ 89,844	3.2%
Other Costs				
Power Supply Costs	461,686	(1,762)	459,924	-0.2%
Operating Costs	69,736	3,490	73,226	0.5%
Employee Future Benefit Costs	6,159	(3,388)	2,771	-0.5%
Deferred Cost Recoveries and Amortization	-	444	444	0.1%
Depreciation	74,745	507	75,252	0.1%
Income Taxes	13,294	10,904	24,198	1.5%
	625,620	10,195	635,815	
Total Costs and Return	693,103	32,556	725,659	
Adjustments				
Other Revenue	(4,679)	(1,794)	(6,473)	-0.3%
Interest on Security Deposits	18	-	18	-
Energy Supply Cost Variance Adjustments	26,665	(26,665)	-	-3.8%
Demand Management Incentive Adjustments	(2,079)	2,079	-	0.3%
Other Transfers to RSA	(4,630)	(1,771)	(6,401)	-0.3%
	15,295	(28,151)	(12,856)	
Elasticity Adjustment	(1,075)	1,075	-	0.2%
2023 Revenue Requirement from Rates	**707,323**	**5,480**	**712,803**	0.8%
RSA	2,444	(6)	2,438	0.0%
MTA	17,005	104	17,109	0.0%
Elasticity Adjustment	(33)	33	-	0.0%
Billed to Customers	**$ 726,739**	**$ 5,611**	**$ 732,350**	0.8%

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. 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 $4,281,000 in 2022 and $5,480,000 in 2023, which the Company is proposing to obtain by increasing rates effective March 1, 2022 by an average of 0.8%.

Return on rate base and equity, capital structure and interest coverage

Calculation of average rate base

The Company's calculations of its forecast average rate base for the years ending December 31, 2021, 2022 and 2023 are included on Exhibit 3 page 5 of 9 and Exhibit 6 of the pre-filed evidence. Our procedures with respect to verifying the calculation of average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including prior years audited financial statements and internal accounting records, where applicable;

- agreed forecast data (capital expenditures; depreciation; etc.) to supporting documentation to ensure it is internally consistent with pre-filed evidence and other areas of the forecast;

- checked the clerical accuracy of the continuity of the rate base as forecast for 2021, 2022 and 2023;

- recalculated the forecast rate base for 2021, 2022 and 2023; and,

- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act and relevant Board Orders to ensure it is in accordance with established policy and procedure.

The following table summarizes the 2022 and 2023 average rate base as existing and as proposed:

Table 3: Average Rate Base 2022-2023

	2022				2023			
(000's)	**Existing**	**Impact**	**Ref.**	**Proposed**	**Existing**	**Impact**	**Ref.**	**Proposed**
Net Plant Investment	$ 1,209,201	$ (265)	(1)	$ 1,208,936	$ 1,261,498	$ (735)	(1)	$ 1,260,763
Add:								
Defined Benefit Pension Costs	91,526	-		91,526	98,201	-		98,201
Cost Recovery Deferrals								
Credit Facility Costs	24	(8)	(2)	16	10	(10)	(2)	-
Hearing Costs	-	247	(3)	247	-	371	(3)	371
Conservation	17,841	98	(4)	17,939	18,343	401	(4)	18,744
Electrification	935	1,009	(5)	1,944	935	3,245	(5)	4,180
2022 Revenue Shortfall	-	312	(6)	312	-	468	(6)	468
Weather Normalization Reserve (a)	(1,958)	1,958		-	-	-		-
Demand Management Incentive Account	1,268	(634)	(7)	634	1,361	(1,361)	(7)	-
Customer Finance Programs	2,166	-		2,166	2,202	-		2,202
	111,802	2,982		114,784	121,052	3,114		124,166
Deduct:								
Other Post Employee Benefits	74,950	-		74,950	80,572	-		80,572
Customer Security Deposits	1,212	-		1,212	1,212	-		1,212
Accrued Pension Obligation	5,430	-		5,430	5,578	-		5,578
Accumulated Deferred Income Taxes	15,997	(81)	(8)	15,916	23,784	83	(8)	23,867
Weather Normalization Reserve (a)	-	1,958		1,958	-	-		-
	97,589	1,877		99,466	111,146	83		111,229
Average Rate Base Before Allowances	1,223,414	840		1,224,254	1,271,404	2,296		1,273,700
Cash Working Capital Allowance	10,326	(3,778)	(9)	6,548	10,096	(3,296)	(9)	6,800
Materials and Supplies Allowance	8,218	538	(10)	8,756	8,358	547	(10)	8,905
Average Rate Base at Year End	**$ 1,241,958**	**$ (2,400)**		**$ 1,239,558**	**$ 1,289,858**	**$ (453)**		**$ 1,289,405**

(a) The Company has presented the balance as a negative figure in the additions from rate base in Exhibit 3 of the Application. In effect, this is a deduction to rate base and has been presented as a deduction to average rate base for presentation purposes in this table.

(1) Net Plant Investment – In 2022, the decrease of net plant investment in proposed compared to existing relates to the proposed changes due to the 2019 Depreciation Study. Additionally, the 2023 decrease is a result of the impact of changes proposed for the accounting for GEC as well as the 2019 Depreciation Study. Impact on net plant investment for 2022 and 2023 is $265,000 and $735,000 decreases respectively.

(2) Credit Facility Costs – For test year revenue requirement purposes, unamortized credit facility costs are included in the calculation of the Company's weighted average cost of capital. Between test years, any additional costs incurred associated with amendments to the credit facility are reflected in rate base as they have not yet been reflected in the Company's weighted average cost of capital and/or customer rates. Impact on average rate base for 2022 and 2023 are $8,000 and $10,000 decreases respectively.

(3) Hearing Costs – The increase of hearing costs in proposed compared to existing relates to the expectation that $1,000,000 will be incurred by the Board and Consumer Advocate related to the Application. The Company is proposing these costs be recovered in customer rates evenly over a 34-month period from March 1, 2022 to December 31, 2024. Impact on hearing costs for 2022 and 2023 are $247,000 and $371,000 increases respectively.

(4) Conservation – The increase of conservation deferrals in proposed compared to existing is a result of the change in amortization from 7 to 10 years as proposed by the Company. The impact on conservation deferrals for 2022 and 2023 are $98,000 and $401,000 increases respectively.

(5) Electrification – On December 16, 2020 the Company filed the *"2021 Electrification, Conservation and Demand Management Application"* which remains under review with the Board. Therefore, the

$935,000 expenditure from 2021 which appears under existing for 2022 and 2023 is an unapproved addition to rate base. For 2022 and 2023 the increase of electrification deferrals in proposed compared to existing is a result of costs deferred as part of the electrification program, offset partially by the amortization of costs over 10 years as proposed. Impact on electrification deferrals for 2022 and 2023 are $1,009,000 and $3,245,000 increases respectively.

(6) 2022 Revenue Shortfall – The increase of revenue shortfall in proposed compared to existing is a result of 2022 revenue shortfall of $1,262,000 related to the March 1, 2022 rate implementation and amortization of the revenue shortfall over a 34-month period. Impact on 2022 revenue shortfall for 2022 and 2023 are $312,000 and $468,000 increases respectively.

(7) Demand Management Incentive Account – The decrease of the Demand Management Incentive Account is due to the rebasing of the unit demand cost to the test year value resulting in $Nil balances in the account for test years 2022 and 2023. Impact of Demand Management Incentive Account for 2022 and 2023 are $634,000 and $1,361,000 decrease respectively.

(8) Accumulated Deferred Income Taxes – The decrease in deferred income taxes for 2022 in proposed compared to existing is due to changes in depreciation as a result of the 2019 Depreciation Study. The increase in deferred income taxes in proposed in 2023 compared to existing is due to the change in accounting for GEC, partially offset by a decrease due to the impact of applying the 2019 Depreciation Study. Impact on accumulated deferred income taxes for 2022 and 2023 is a $81,000 decrease and a $83,000 increase, respectively.

(9) Cash Working Capital Allowance – The decrease in the cash working capital is a result of a decrease in the cash working capital factor from 1.8% for 2019/2020 test years to 1.1% and 1.2% for the 2022 and 2023 test years respectively, as a result of a decrease in the net lag days relating to collection of revenue and payment of costs. Impact on cash working capital allowance for 2022 and 2023 are $3,778,000 and $3,296,000 decreases respectively.

(10) Materials and Supplies Allowance – The increase in the materials and supplies allowance is a result of a lower expansion factor deduction used in the proposed average rate base. The Company has revised the Materials Allowance expansion factor to 19.08% for the 2022/2023 test years versus 24.05% calculated for the 2019/2020 test years. Impact on material and supplies allowance for 2022 and 2023 are $538,000 and $547,000 increases respectively.

Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the average rate base, and therefore conclude that the forecast average rate base included in the Company's pre-filed evidence is in accordance with established practice. We also conclude that the proposed average rate base accurately reflects the Company's proposals with respect to the change in accounting for GEC, regulatory deferral accounts, the 2019 Depreciation Study, and the updated calculations related to the rate base allowances.

Return on rate base

Our procedures with respect to verifying the calculation of forecast return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the forecast rate of return to ensure it is in accordance with established practice and Board Orders.

The following table provides the 2019 to 2020 actual return on rate base, the Company's forecast rate of return on rate base for 2021 to 2023, the Company's proposed return on rate base for 2022 and 2023 and the upper and lower end of range as set by the Board:

Table 4: Return on Average Rate Base 2019-2023

	Actual		Forecast			Proposed	
	2019	2020	2021	2022	2023	2022	2023
Actual Return on Average Rate Base	6.97%	7.04%	6.46%	5.90%	5.23%	7.19%	6.97%
Upper End of Range set by the Board	7.19%	7.22%	6.83%			7.37%	7.15%
Lower End of Range set by the Board	6.83%	6.86%	6.47%			7.01%	6.79%

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"). In Order No. P.U. 25 (2011), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019), the Board approved the suspension of the operation of the Formula to establish a rate of return on rate base. The appropriateness of the Company's proposal to discontinue the use of the Formula will be reviewed by the cost of capital experts participating in this hearing.

In Order No. P.U. 2 (2019), the Board approved a rate of return on average rate base for 2019 of 7.01% in a range of 6.83% to 7.19% and a rate of return on average rate base for 2020 of 7.04% in a range of 6.86% to 7.22%. In Order No. P.U. 36 (2020) the Board approved a 2021 rate of return on average rate base of 6.65%, in a range of 6.47% to 6.83%. The Company is proposing the Board approve a return on average rate base for 2022 of 7.19%, within a range of 7.01% to 7.37% and for 2023 of 6.97%, within a range of 6.79% to 7.15%.

Based upon the results of the above procedures, we did not note any discrepancies in the Company's calculation of the return on average rate base, and therefore conclude that the forecast return on average rate base included in the Company's pre-filed evidence has been calculated in accordance with established practice. We also conclude that the proposed rate of return on average rate base accurately reflects the proposals in this Application as well as the Company's targeted return on equity of 9.8%.

Capital structure

In Order No. P.U. 43 (2009) the Board confirmed its previous position regarding the capital structure for Newfoundland Power comprised of 45% equity, 54% debt and 1% preferred equity. In Order Nos. P.U. 13 (2013), P.U. 18 (2016), and P.U. 2 (2019) the Board maintained its position for equity not to exceed 45% of capital structure.

Average forecast common equity for 2021 through 2023, including the proposed average common equity for 2022 and 2023 per the pre-filed evidence, is below the approved maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

In its pre-filed evidence, the Company is proposing to maintain a capital structure which is consistent with the structure established by Order Nos. 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) and P.U. 2 (2019).

Based on our recalculations of the components of the capital structure, the Company's projected average capital structure for 2019 through 2023 is as follows:

Table 5: Capital Structure 2019-2023

	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023	Proposed 2022	Proposed 2023
Debt	54.28%	54.70%	55.43%	55.69%	56.18%	55.14%	55.04%
Equity[1]	45.72%	45.30%	44.57%	44.31%	43.82%	44.86%	44.96%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

(1) Equity includes common and preferred for 2019 and 2020; preferred shares were redeemed in 2020.

The above table shows that the Company's forecast average common equity for 2021 to 2023 is below the 45% maximum approved by the Board. The debt portion of the cost of capital for 2021 and 2022 proposed is 5.07% and 4.66% 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).

The proposed capital structure for 2022 and 2023 is consistent with the position confirmed by the Board in Order No. P.U. 2 (2019). The above calculations of capital structure are consistent with Exhibit 3 (Page 6 of 9) and Exhibit 5 (Page 6 of 9) presented in the 2022/2023 GRA.

Calculation of average common equity and return on average common equity

Newfoundland Power has noted that, based on expert evidence filed with the GRA which indicates a fair return, it is targeting a 2022 and 2023 return on equity of 9.8%.

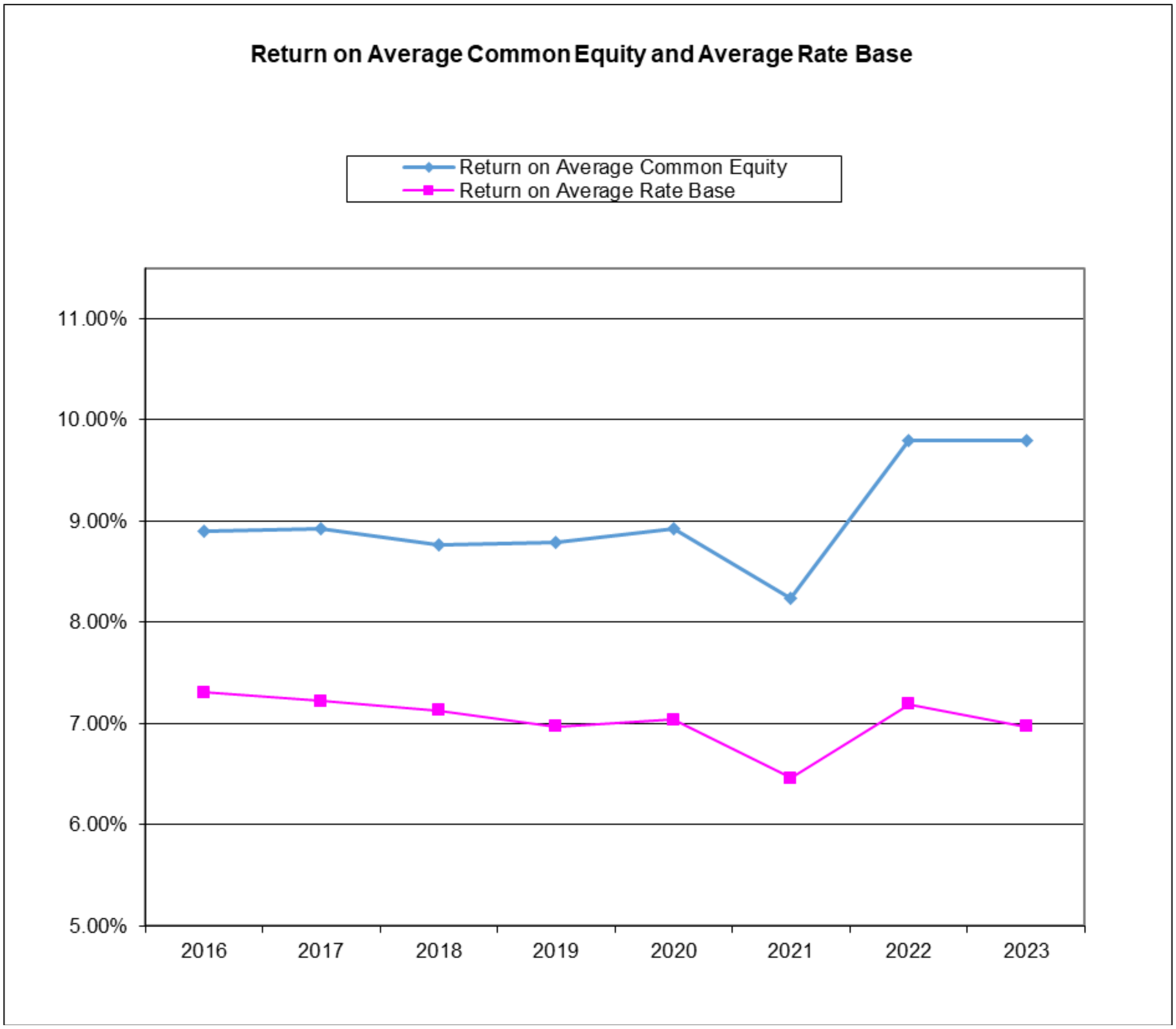
Similar to the approach used to verify the rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;
- agreed forecast data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other areas of the forecast;
- checked the clerical accuracy of the continuity of common equity; and,
- recalculated the forecast rate of return on common equity for 2021, 2022 and 2023 to ensure it is in accordance with established practice.

The following is a comparison of the actual return on average common equity from 2016 to 2020, forecast for 2021 and proposed 2022 and 2023 with the actual return on average rate base for 2016 to proposed 2023:

Table 6: Average Common Equity vs. Return on Average Rate Base 2016-2023

	2016	2017	2018	2019	2020	Forecast 2021	Proposed 2022	Proposed 2023
Return on Average Common Equity	8.90%	8.93%	8.76%	8.79%	8.93%	8.24%	9.80%	9.80%
Return on Average Rate Base	7.31%	7.22%	7.13%	6.97%	7.04%	6.46%	7.19%	6.97%
Spread between actual returns	1.59%	1.71%	1.63%	1.82%	1.89%	1.78%	2.61%	2.83%



As demonstrated by the graph above, the proposed 2022 and 2023 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.

Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the forecast and proposed rate of return on average common equity for 2021, 2022 and 2023. A review of the 2022 and 2023 proposed rate of return on common equity in this Application is beyond the scope of our report.

Interest coverage

The level of interest coverage experienced by the Company in 2020 and as forecasted, is as follows:

Table 7: Interest Coverage 2020-2023[1]

(000's)	Actual 2020	Forecast 2021	Existing 2022	Proposed 2022	Existing 2023	Proposed 2023 (2)
Income before taxes	$ 55,470	$ 51,137	$ 43,988	$ 65,751	$ 37,298	$ 69,579
Interest on long term debt	36,811	35,452	36,005	36,005	34,945	34,945
Other interest	609	348	328	435	752	892
Capitalized interest	(949)	(1,317)	(1,943)	(1,943)	(2,963)	(2,964)
Amortization of debt issue expenses	233	212	197	197	183	183
Total	92,174	85,832	78,575	100,445	70,215	102,635
Interest on long-term debt	36,811	35,452	36,005	36,005	34,945	34,945
Other interest	609	348	328	435	752	892
Amortization of debt issue expenses	233	212	197	197	183	183
Total	$ 37,653	$ 36,012	$ 36,530	$ 36,637	$ 35,880	$ 36,020
Interest coverage (times)	**2.4**	**2.4**	**2.2**	**2.7**	**2.0**	**2.8**

(1) Interest coverage is calculated at the company level, including both regulated and non-regulated operations.
(2) We calculated an interest coverage of 2.8 for 2023 proposed, however Table 3-16 on page 3-43 presents 2.9.

In Order No. P.U. 43 (2009), the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. In 2019 and 2020 as per the Company's Exhibit 3 (page 1 of 9), interest coverage was 2.4 in each of the years. The forecast ratios for 2021, 2022 and 2023 under existing rates are 2.4, 2.2 and 2.0 times respectively. As indicated above, the proposals included in this Application result in interest coverage for 2022 and 2023 of 2.7 and 2.8 respectively.

The appropriateness of the level of interest coverage is linked to the proposed return on common equity and therefore is outside the scope of our report.

Operating expenses

Using the information presented in Schedule 1 and Schedule 2 of our report, the operating costs per customer from actual 2019 to proposed 2023 are as follows:

Table 8: Operating Costs by Customer 2019-2023

	Actual 2019	Actual 2020	Forecast 2021	Proposed 2022	Proposed 2023
Number of customers	269,045	270,285	271,298	272,253	273,165
Gross operating expenses (000's)	$ 78,165	$ 82,953	$ 86,853	$ 85,437	$ 82,320
Net operating expenses (000's)	$ 71,280	$ 78,591	$ 79,988	$ 76,240	$ 75,997
Gross operating expense per customer	$ 290.53	$ 306.91	$ 320.14	$ 313.81	$ 301.36
Net operating expense per customer	$ 264.94	$ 290.77	$ 294.83	$ 280.03	$ 278.21

Based on the above information, the gross operating expense per customer increased by 5.6% from 2019 to 2020 and is forecast to decrease by 1.8% from 2020 to proposed 2023. Net operating expense per customer increased by 9.8% from 2019 to 2020 and is forecast to decrease by 4.3% from 2020 to proposed 2023.

Our review of operating expenses was conducted using the breakdown of expenses as outlined in Exhibit 1 and Exhibit 2 of the pre-filed evidence. These exhibits provide details of the actual operating expenses for the years 2019 and 2020 as well as the forecast for 2021, 2022 and 2023.

Schedule 1 of our report presents the total cost of energy to kWhs sold from actual 2019 to 2020 and the forecast total cost of energy to forecast kWhs for 2021, 2022 and 2023. The table and graph show that the total cost of energy per kWh increased by 7.3% from 2019 to 2020 ($0.1161 to $0.1246) and is forecast to increase by 2.9% from 2020 to proposed 2023 ($0.1246 to $0.1282). This increase is primarily attributable to the increase in depreciation, as well as the increase in the return on common equity to 9.8% included in this Application.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 2 of our report. The table and graph show that the cost per kWh increased from $0.0134/kWh in 2019 to $0.0145/kWh in 2020. The cost per kWh was then forecast to fluctuate over the forecast years, ending at same cost per kWh as 2020 of $0.0145/kWh for proposed 2023. The change from 2020 to 2023 shows an increase in customer services of $6,652,000, primarily due to the increase in program costs for CDM and Electrification; Schedule 2 presents gross operating costs prior to the proposed allocation of these costs to deferral accounts. This increase is offset by a reduction in general operating costs of $7,563,000, where the biggest contributor to the decrease relates to employee future benefits for $11,620,000, partially offset by an increase of $3,219,000 in Information Systems and Corporate & Employee Services.

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.

Operating expenses - key variances

Based upon our review of Exhibit 1 “Operating Costs by Function” and Exhibit 2 “Operating Costs by Breakdown” of the Company’s pre-filed evidence, the following key variances between 2019 actual and 2023 forecast have been noted, along with explanations provided by the Company:

Table 9: Exhibit 1 – Operating Costs by Function 2019-2023

($000's)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Distribution	$ 10,236	$ 10,945	$ 9,227	$ 9,487	$ 9,741
Transmission	712	919	957	978	999
Substations	2,361	2,258	2,356	2,422	2,487
Power produced	3,940	3,797	3,930	4,027	4,122
Administrative & Engineering Support	7,972	7,934	8,204	8,433	8,657
Telecommunications	1,286	1,299	1,350	1,374	1,397
Environment	287	273	282	289	296
Fleet Operations & Maintenance	1,679	1,719	1,666	1,695	1,723
Electricity Supply	**28,473**	**29,144**	**27,972**	**28,705**	**29,422**
Customer Services	7,726	7,468	7,875	8,038	8,103
Conservation	728	679	782	886	946
Uncollectible Bills	1,980	2,290	2,135	2,172	2,208
Customer Services	**10,434**	**10,437**	**10,792**	**11,096**	**11,257**
Information Systems	5,402	5,855	6,051	6,407	7,311
Financial Services	1,787	1,806	1,886	1,942	1,997
Corporate & Employee Services	14,233	14,504	15,529	16,052	16,267
Insurances	1,397	1,698	2,079	2,306	2,345
General	**22,819**	**23,863**	**25,545**	**26,707**	**27,920**
Gross Operating Cost	**$ 61,726**	**$ 63,444**	**$ 64,309**	**$ 66,508**	**$ 68,599**

- Distribution – The Company has indicated in the Application that the decrease in distribution from 2020 to 2023 is primarily reflected in the reduced maintenance requirements for streetlights due to the implementation of the LED Street Light Replacement Plan.
- Transmission – The Company has noted that transmission operating costs increased from 2019 to 2020 primarily due to increased vegetation management activity. Vegetation management cost vary from year to year as a result of planned maintenance activities and weather conditions. Increase in transmission operating costs in 2021 to 2023 are related to inflation.
- Substations – According to the Company the substation expense decreased from 2019 to 2020 as a result of lower substation maintenance cost. This expense can fluctuate from year to year primarily due to external professional service cost required for both planned and unplanned maintenance work. Increase in substation costs in 2021 to 2023 are related to inflation and higher external professional service costs.
- Environment – The Company noted that environment costs decreased from 2019 to 2020 as a result of lower operating costs relating to spill responses in 2020. The increase in environment operating costs in 2021 to 2023 are primarily related to labour inflation.
- Customer Services – The Company has indicated in the Application that customer service expense from 2019 to 2023 is forecast to increase primarily due to labour inflation, which is partially offset by operating efficiencies gained through replacement of the existing Customer Service System.
- Conservation – The Company has indicated in the Application that conservation expense from 2019 to 2023 is forecast to increase due to the implementation of the new Electrification, Conservation and Demand Management Plan 2021-2025. These costs represent non-program costs not eligible for deferral under the Company’s proposed definitions for the CDM and Electrification Cost Deferral Account filed in Exhibit 12 and Exhibit 13, respectively.

- Uncollected Bills – According to the Company the uncollected bills expense increased from 2019 to 2020 as a result of an increase in uncollectible bills which was caused by the suspension of collecting activities and offers of more flexible payment arrangements for customers during the global pandemic. The 2021 forecast reflects the two-year average of 2019 and 2020 which represents an anticipated recovery from the economic impacts of the pandemic and resumption of collection activity. The increase in uncollectible bills for 2022 and 2023 are related to inflation.
- Information Systems – The Company noted that the higher information systems costs throughout the forecast period primarily reflect an increase of approximately $1.6 million in licensing and support costs for third-party hardware and software solutions, including cybersecurity costs.
- Corporate and Employee Services – According to the Company the corporate and employee services expense from 2019 to 2023 is forecast to increase due to inflationary increases of approximately $1.3 million and additional regulatory costs: the addition of a director position to oversee the Company's Regulatory Affairs function; an analyst position in the department; and increased other company fees.

Table 10: Exhibit 2 – Operating Costs by Breakdown 2019–2023

($000's)	**Actual 2019**	**Actual 2020**	**Forecast 2021**	**Forecast 2022**	**Forecast 2023**
Regular and Standby	$ 30,068	$ 31,483	$ 30,703	$ 31,677	$ 32,634
Temporary	2,151	1,625	1,990	2,050	2,108
Overtime	3,022	3,425	3,204	3,300	3,394
Total Labour	**35,241**	**36,533**	**35,897**	**37,027**	**38,136**
Vehicle Expenses	1,681	1,725	1,673	1,702	1,730
Operating Materials	1,359	1,300	1,244	1,266	1,287
Inter-Company Charges	27	26	27	27	28
Plans, Subs, System, Oper & Bldgs	3,267	3,484	3,376	3,434	3,492
Travel	1,089	633	861	876	891
Tools and Clothing Allowance	1,289	1,156	1,223	1,244	1,265
Miscellaneous	1,450	1,633	1,542	1,568	1,595
Taxes and Assessments	1,156	1,116	1,142	1,162	1,181
Uncollectible Bills	1,980	2,290	2,135	2,172	2,208
Insurance	1,397	1,698	2,079	2,306	2,345
Severance & Other Employee Cost	132	126	129	131	133
Education, Training, Employee Fees	418	267	343	348	354
Trustee and Directors' Fees	518	673	689	701	712
Other Company Fees	2,428	2,131	2,610	2,868	2,874
Stationery & Copying	257	246	252	256	260
Equipment Rental/ Maintenance	790	656	770	832	897
Telecommunications	1,473	1,473	1,535	1,562	1,588
Postage	1,329	1,313	1,283	1,244	1,202
Advertising	573	460	517	525	534
Vegetation Management	2,042	2,306	2,359	2,401	2,441
Computing Equipment & Software	1,830	2,199	2,623	2,856	3,446
Total Other	**26,485**	**26,911**	**28,412**	**29,481**	**30,463**
Gross Operating Cost	**$ 61,726**	**$ 63,444**	**$ 64,309**	**$ 66,508**	**$ 68,599**

- Temporary labour expense – The Company has indicated that temporary labour expense is forecast to decrease from 2019 to 2023. This cost reflects an average of the amount of temporary labour required over the last 3 years, adjusted for labour inflation.

- Travel expense – The Company has noted that 2020 travel expense was lower than 2019 due primarily to company wide restrictions on travel as a result of the global pandemic as well as lower employee relocation costs. The 2021 forecast represents a two-year average of 2019 and 2020 and represents the gradual lifting of company wide travel restrictions. While public health measures related to the pandemic have continued into 2021, they are expected to ease throughout the year as the Provincial Government implements its vaccination plans. The increase in travel expenses for 2022 and 2023 are related to inflation.
- Insurance expense – According to the Company the insurance expense forecasted increase from 2019 to 2023 is reflective of an increase in Newfoundland Power's insurance premium, which is consistent with general market trends. Further details included in response to NLH-NP-004 provides support and explanation of 2022 and 2023 insurance forecasts.
- Education, Training, Employee Fees – The Company has noted that 2020 expenses were lower than 2019 due primarily to lower costs associated with conferences and group training sessions due to COVID-19 restrictions. The 2021 forecast represents a two-year average of 2019 and 2020 and represents the gradual lifting of company wide travel restrictions. While public health measures related to the pandemic have continued into 2021, they are expected to ease throughout the year as the Provincial Government implements its vaccination plans. The increase in education, training, employee fees for 2022 and 2023 are related to inflation.
- Other company fees – The Company has noted that the 2020 expense is lower than 2019 due primarily to lower regulatory activity in 2020. The increase in the 2021 forecast reflects the anticipated increase in regulatory activity in the year. This includes additional external consultant costs related to regulatory proceedings such as Newfoundland Power's 2022/2023 GRA and ongoing proceedings such as the Capital Budget Guidelines Review. Furthermore, according to the Company the 2022 and 2023 forecast primarily reflects additional external consultant costs related to regulatory proceedings such as: (i) NL Hydro's next general rate application, including cost of service and other matters associated with commissioning of the Muskrat Falls project; (ii) Newfoundland Power's next general rate application; and (iii) the 2023 OPEBs actuarial valuation.
- Equipment Rental/Maintenance – The Company has noted that the 2020 expense is lower than 2019 due primarily to decreased equipment rentals and reduced printer service usage charges as a result of the global pandemic and the requirement for employees to work from home while strict public health measures were in place. The increase in the 2021 forecast primarily reflects additional costs for new equipment coming off their original purchase warranties and a forecast increase in equipment rentals compared to 2020. While public health measures related to the pandemic have continued into 2021, they are expected to ease throughout the year as the Provincial Government implements its vaccination plans. Furthermore, the Company noted the increase in the 2022 and 2023 forecasts primarily reflects additional costs for new equipment coming off their original purchased warranties in each year. This includes items such as production printers and servers.
- Advertising – The Company has noted that advertising expenses were lower in 2020 compared to 2019 primarily due to the development of new safety advertising being delayed as a result of COVID-19. The 2021 forecast represents a two-year average of 2019 and 2020. The increase in advertising for 2022 and 2023 are related to inflation.
- Computing Equipment and Software – The Company has noted that increases in computing equipment and software expenses are due to higher licensing and support costs for third party hardware and software solutions. The increased cost from 2019 to 2023 forecast includes approximately: $208,000 for infrastructure and network management; $268,000 for cybersecurity management; $439,000 for customer service software, such as the replacement Customer Information System; $183,000 for business back office software, such as the Human Resources Management System; and $517,000 for operations and engineering software, such as the Outage Management System.

Based upon our review and analysis, nothing has come to our attention to indicate that the 2021, 2022 and 2023 forecast operating expenses are unreasonable on an overall basis.

Executive compensation

The following table provides a summary and comparison of executive compensation for forecast 2021, 2022 and 2023 with actuals for 2019 and 2020:

Table 11: Average Compensation Per Executive 2019-2023

	Base Salary	Incentive (Note 1)	Other (Note 2)	Total	% Change
Forecast 2023					
Total executive group	$ 1,338,000	$ 476,000	$ 136,000	$ 1,950,000	2.8%
Average per executive	$ 334,500	$ 119,000	$ 34,000	$ 487,500	
Forecast 2022					
Total executive group	$ 1,301,000	$ 463,000	$ 132,000	$ 1,896,000	3.0%
Average per executive	$ 325,250	$ 115,750	$ 33,000	$ 474,000	
Forecast 2021					
Total executive group	$ 1,264,000	$ 449,000	$ 128,000	$ 1,841,000	-43.8%
Average per executive	$ 316,000	$ 112,250	$ 32,000	$ 460,250	
2020					
Total executive group	$ 1,269,167	$ 667,000	$ 1,339,436	$ 3,275,603	38.8%
Average per executive	$ 317,292	$ 166,750	$ 334,859	$ 818,901	
2019					
Total executive group	$ 1,235,000	$ 703,000	$ 421,412	$ 2,359,412	
Average per executive	$ 308,750	$ 175,750	$ 105,353	$ 589,853	

Note 1: The forecast periods incentive payments reflect regulated portion only and are based on achieving 100% of target. Actual years reflect both regulated and non-regulated compensation.

Note 2: The "other" category of the annual compensation package includes items such as vehicle benefits or car allowance, insurance benefits, and self-directed RRSP employer contributions.

The Company indicated that they used Korn Ferry Limited to provide external expertise to assist with the review of salaries and wages for the executive and senior management employees. On October 14, 2020 Korn Ferry provided a report titled “Executive Compensation – 2021 Estimated Market Actual Salary Median.” The report provides an estimate of the market annual salary levels in 2021 for members of Newfoundland Power’s executive team. This analysis was based upon Commercial Industrial market data in effect on May 1, 2020. 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 2021, the Company's executive salary policy versus the actual base salary for executives is outlined in the table below:

Table 12: Executive Compensation – Actual vs. Policy

Position	Base Salary	Salary Policy[1]	Korn Ferry Median[2]	Difference From Policy	Base as % of Policy
President & CEO	$ 397,000	$ 455,800	$ 455,800	$ (58,800)	87%
VP Customer Operations	285,000	321,500	321,500	(36,500)	89%
VP Finance & CFO	288,500	288,500	288,500	-	100%
VP Energy Supply & Planning	293,000	303,700	303,700	(10,700)	96%
Total	**$ 1,263,500**	**$ 1,369,500**	**$ 1,369,500**	**$ (106,000)**	**92%**

(1) Provided by the Company based on advice of Korn Ferry effective August 17, 2020.

(2) Korn Ferry median from letter dated October 14, 2020.

The base salary presented corresponds to the approved minutes from the meeting of the Board of Directors on February 2, 2021.

Salaries and benefits

Our review of salaries and benefits included an analysis of the year-to-year variance, consideration of the trends in labour costs and investigation of significant variances.

A detailed comparison of the number of full-time equivalent ("FTE") employees for 2019 to forecast 2023 is as follows:

Table 13: Full-time Equivalents

	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Permanent	576	578	598	602	600
Temporary	40	34	26	40	25
Total	616	612	624	642	625
Managerial FTE`s	276	278	276	280	279
% managerial	45%	45%	44%	44%	45%
Union FTE`s	300	300	322	322	321
% union	49%	49%	52%	50%	51%

According to the Company, FTEs are determined by applying a vacancy allowance. The assumptions in determining vacancy allowances is included in the Company's report titled "*Labour Forecast 2021-2023".*

The Company's report provided detailed information concerning the methodology used to forecast test year FTEs and labour expense, as well as assumptions used to determine forecast vacancies as part of its pre-filed evidence for this GRA. In this report, Newfoundland Power states that current labour requirements tend to be consistent from year to year. The Company has noted that this is primarily due to the fact that the Company matches overall capacity and capability with anticipated work requirements when managing its workforce.

The 2021 forecast shows an increase of 12 FTE's, which is primarily due to additional labour associated with new customer electrification programs, the Customer Service Systems (CSS) Replacement Project and the Company's PLT Apprentice program. FTE's and internal labour expense in 2021 also includes employees that worked a partial year in 2020 but are anticipated to be in the workforce for a full year in 2021, partially offset by employees who left in 2020. Furthermore, the Company explained that the 2021 increase in regular FTE's for the union category is primarily driven by a shift from temporary to regular full-time positions for customer service representatives.

The 2022 forecast shows an increase of 18 FTE's, primarily due to the addition labour associated with the CSS Replacement Project. Finally, the 2023 forecast reflects an overall decrease of 17 FTE's, primarily due to the conclusion of the CSS Replacement Project.

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 2019 to forecast 2023 are included in the table below:

Table 14: Salary Cost per FTE

(000's)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Salary costs	$66,023	$69,028	$72,284	$75,973	$76,155
Benefit costs (net)	(8,926)	(9,563)	(10,273)	(10,581)	(10,883)
Other adjustments	(1,126)	(1,693)	(1,031)	(711)	(845)
Base salary costs	55,971	57,772	60,980	64,681	64,427
Less: executive compensation(1)	(1,938)	(1,936)	(1,780)	(1,834)	(1,885)
Base salary costs (excluding executive)	$54,033	$55,836	$59,200	$62,847	$62,542
FTE's (including executive members)	616	612	624	642	625
FTE's (excluding executive members)	612	608	620	638	621
Average salary per FTE	$90.9	$94.5	$97.7	$100.7	$103.1
% increase		3.98%	3.44%	3.10%	2.32%
Average salary per FTE (excluding executive members)	$88.3	$91.9	$95.5	$98.5	$100.7
% increase		4.10%	3.89%	3.17%	2.24%

(1) Reflects both regulated and non-regulated compensation.

(2) Rounding differences in above table due to presentation.

In the *"Labour Forecast 2021-2023"* report, the Company has noted that the 2022 and 2023 salary increase is based on a weighted average salary increase of 3.00% and 2.85% respectively. The following table provides the breakdown of the Company's weighted labour rate from 2020 to 2023:

Table 15: Weighted Labour Rate

(%)	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Base Rate[1]	2.04	2.00	2.25	2.10
Progression Rate[2]	0.88	0.75	0.75	0.75
Total	**2.92**	**2.75**	**3.00**	**2.85**

Note 1 - reflects the Company's bargained annual increases agreed between the Company and its union and market changes for non-union employees. The Company has two collective agreements in effect until June 30, 2022. For 2023, the forecast base increase is a three year average.

Note 2 - reflects the additional wage employees receive as they progress through their position. For union employees, labour progression is included in the Collective Agreement. The progression rate for the Company was 0.88% in 2020, or 0.79% when excluding Executive and Senior Management changes. An annual estimate of 0.75% is forecast for the progression rate from 2021 through 2023.

The following table provides the detailed breakdown of forecast internal labour expenses as per the Company's "*Labour Forecast 2021-2023"* report:

Table 16: Internal Labour Forecast 2020-2023

(000's)	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Operating	$ 33,108	$ 32,693	$ 33,727	$ 34,742
Capital	23,510	26,446	29,006	27,972
Rechargeable & Recoverable	8,302	8,614	8,811	8,957
Total[1]	**$ 64,920**	**$ 67,753**	**$ 71,544**	**$ 71,671**

(1) - The difference from the internal labour presented in table 17 and the internal labour forecast totals from the Labour Forecast 2021-2023 report is due to the inclusion of the non-regulated labour, CDM program labour, electrification program labour, and OPEB current service costs in table 17 figures.

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

Table 17: Salary Costs by Function 2019-2023

(000's)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Type					
Internal labour	$ 66,023	$ 69,028	$ 72,284	$ 75,973	$ 76,155
Overtime	6,568	5,886	6,341	6,531	6,717
	72,591	74,914	78,625	82,504	82,872
Contractors	17,523	12,510	15,147	15,602	16,046
Total	$ 90,114	$ 87,424	$ 93,772	$ 98,106	$ 98,918
Function					
Operating[1]	$ 38,603	$ 40,652	$ 40,496	$ 41,536	$ 42,701
Capital miscellaneous	51,511	46,772	53,276	56,570	56,217
Total	$ 90,114	$ 87,424	$ 93,772	$ 98,106	$ 98,918

(1) The operating labour figures provided in Exhibit 2 for 2019 to 2023 forecast excludes non-regulated expenses, CDM program labour, electrification program labour, 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	**$ 35,241**	**$ 36,533**	**$ 35,897**	**$ 37,027**	**$ 38,136**
Non-regulated labour	1,170	1,660	1,152	791	925
CDM Program Labour	1,154	1,169	1,423	1,520	1,401
Electrification Program Labour	-	-	343	449	420
OPEB current service costs	1,038	1,290	1,681	1,749	1,819
Operating Labour, above	**$ 38,603**	**$ 40,652**	**$ 40,496**	**$ 41,536**	**$ 42,701**

The Company's operating labour costs are forecast to increase by approximately 2.1% annually over the period of 2019 to 2023. The Company's annual labour rate inflation is approximately 3.1% over the same period, which we recalculated during our procedures. Newfoundland Power stated that this implies an efficiency of 1.0% per year[2]. According to the Company, the efficiencies are not a result of changes in capitalization of labour but a reduction of operating labour requirements attributable to new technologies such as computing software or the LED Street Lighting Replacement Plan.

The increase in labour expense in 2023 is primarily driven by the forecast salary increase based on a weighted labour rate of 2.85%. This equates to an increase of approximately $2,039,000 when compared to 2022. This increase in labour expense is largely offset by decrease of $1,740,000 resulting from the reduction in FTEs at the conclusion of the CSS Replacement Project and the Instant Rebates Program.[3]

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 currently monitors several corporate performance measures. In response to Request for Information PUB-NP-019, the Company has provided the following description of the performance measures:

- **Controllable Operating Cost per Customer**: This measure is based on budgeted controllable operating expenses. The Company has noted that because some costs are beyond the short-term control of management, inter-company charges, board assessments, severances and regulatory amortizations are excluded from the target.

- **Earnings:** This measure represents corporate earnings as per the year-end audited financial statements. The target is based on the Company's earnings budgeted for the year.

- **Duration of Outages (SAIDI):** This measure represents the reliability of the power system in terms of the duration of outages experienced by customers.

- **Customer Satisfaction:** This measure represents Newfoundland Power's customer satisfaction rating which is obtained through independently conducted quarterly surveys of customers with respect to the Company's service.

- **Cashflow:** This measure represents cashflow from operating activities, before working capital adjustments. This is a key financial metric used by the credit rating agencies in assessing the Company's credit worthiness. In 2019 the 'regulatory performance' measure was replaced by the 'cash flow' measure.

- **Safety (All Injury Frequency Rate):** This measure is the number of injuries per 200,000 hours of work and is a combination of both the number of medical aid and lost time injuries.

[2] PUB-NP-022
[3] PUB-NP-051

The following table outlines the actual results for corporate performance for 2019 and 2020 and targets for 2021:

Table 18: Short-Term Incentive Targets 2019-2021

Measure	Actual 2019	Actual 2020	Forecast 2021
Controllable Operating Cost per Customer	$ 231.0	$ 237.7	$ 240.2
Earnings (millions)	$ 42.3	$ 43.2	$ 43.5
Duration of Outages (SAIDI)	2.34	2.98	2.5
Customer Satisfaction	85.8%	87.6%	86.3%
Cash Flow from Operating Activities (millions)	$ 111.2	$ 136.8	$ 126.4
Safety (All Injury Frequency Rate)	0.37	0.74	0.74

Note: The Company has indicated that targets for 2022 and 2023 have not been finalized and approved by the Board of Directors at the time of this report.

The forecast STI payment includes assumptions regarding the corporate performance as outlined in the table above. The Company forecast performance is based upon achieving 100% of targets.

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:

Table 19: Short-Term Incentive Performance Weightings

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

According to the Company, the individual measures are aligned with the specific focus of the executive or director and are designed to promote leadership in enhancing employee and corporate performance in specific areas of responsibility. Individual measures and weightings are adjusted annually to reflect corporate priorities[4]. The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. For 2020, all measures were met except Duration of Outages (SAIDI).

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2019 and 2020, as well as for forecast results for 2021, 2022 and 2023:

Table 20: Short Term Incentive Payout as a Percent of Base Pay 2019-2023

	Target 2019	Actual 2019	Target 2020	Actual 2020	Target 2021	Target 2022	Target 2023
President	50%	70%	50%	64%	50%	50%	50%
Vice-Presidents	35-40%	50%	35-40%	47%	35-40%	35-40%	35-40%
Directors	15%	18%	15%	20%	15%	15%	15%

The actual STI payouts for 2019 and 2020 and forecast payouts for 2021, 2022, and 2023 are summarized in the below table:

[4] PUB-NP-019

Table 21: Short Term Incentive Payout by Category 2019-2023

	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022(1)	Forecast 2023(1)
President	$ 287,000	$ 265,000	$ 198,500	$ 204,455	$ 210,282
Vice-Presidents	416,000	402,000	317,525	327,051	336,372
Directors	311,000	357,800	282,840	291,325	299,628
Sub-total	$ 1,014,000	$ 1,024,800	$ 798,865	$ 822,831	$ 846,282
Less: Non-regulated portion	(344,833)	(299,085)	(89,000)	(91,670)	(94,283)
Total Regulated	**$ 669,167**	**$ 725,715**	**$ 709,865**	**$ 731,161**	**$ 751,999**

(1) 2022 and 2023 forecast amounts were inflated by 3.00% and 2.85% respectively.

In the response to PUB-NP-019, the Company has stated that 2021, 2022 and 2023 forecast of the STI payouts are based on achieving 100% of targets. As such, 50% of the earnings performance measure is classified as a non-regulated payout. This is in accordance with Order Nos. P.U. 19 (2003) and P.U. 28 (2016), however it should be noted that these Orders were issued prior to the replacement of the regulatory performance measure with the cash flow performance measure in 2019; the cash flow measure is included in regulated expense at 100% of target.

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:

Table 22: Employee Future Benefit Breakdown 2019-2023

(000's)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Pension Expense	$ 3,335	$ 7,864	$ 6,958	$ 912	$ (1,780)
OPEBs Expense	6,240	6,528	7,720	7,833	7,939
Total	**$ 9,575**	**$ 14,392**	**$ 14,678**	**$ 8,745**	**$ 6,159**

Company Pension Plan

For 2021, 2022 and 2023, we reviewed the estimates supporting the forecast gross charge for pension expense of $6,958,000, $912,000 and ($1,780,000) respectively. The 2021 pension expense is forecast to decrease by $906,000 from 2020 with further decreases forecast for 2022 and 2023 of $6,046,000 and $2,692,000, respectively.

The components of pension expense are as follows:

Table 23: Pension Expense Breakdown 2019-2023

(000's)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Pension Expense per Actuary	$ 639	$ 4,757	$ 3,766	$ (2,524)	$ (5,488)
PUP/SERP[1]	347	402	371	379	390
Group and Individual RRSPs	2,370	2,711	2,821	3,057	3,318
Less: Offset	(21)	(7)	-	-	-
Total Pension Expense	**$ 3,335**	**$ 7,863**	**$ 6,958**	**$ 912**	**$ (1,780)**
Year over year % change		136%	-12%	-87%	-295%

Note 1 - Pension uniformity plan (PUP); Supplemental employee retirement program (SERP).

Pension expense is expected to decrease by approximately $5,115,000 between 2019 and 2023.The pension expense for 2020 is higher than 2019 primarily due to higher current service costs and higher amortization of net actuarial losses as a result of a decrease in the discount rate. According to the Company the defined benefit pension expense is forecast to decrease between 2019 and 2023 by approximately $6.1 million. This decrease is primarily due to lower interest costs and changes in actuarial gains and losses.

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.

As a result of the closure of the Defined Benefit Pension Plan, all new employees are required to participate in the Defined Contribution Plan (Individual RRSPs). The employer's portion of the contributions to the Group RRSP has increased from 1.5% to 2.0% of the base salary paid to the plan participants, effective May 2019. Individual RRSP contribution increased as a result of plan amendments which increased the contribution rate from 5.75% to 6.25% as of May 2019 and to 6.5% on January 1, 2021. The increase in Group and Individual RRSPs from 2019 to 2023 is due to increased number of employees, increases in employer matching rates and increases in compensation.

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 2019 and 2020, and forecast for 2021, 2022 and 2023 are as follows:

Table 24: Other Post-Employment Benefits Breakdown 2019-2023

(000's)	**Actual 2019**	**Actual 2020**	**Forecast 2021**	**Forecast 2022**	**Forecast 2023**
OPEBs Accrual	$ 3,657	$ 4,191	$ 5,648	$ 5,818	$ 5,984
Amortization of Transitional Amounts	3,504	3,504	3,504	3,504	3,504
Less: Amount Capitalized	(921)	(1,167)	(1,432)	(1,489)	(1,549)
Total OPEBs Expense	**$ 6,240**	**$ 6,528**	**$ 7,720**	**$ 7,833**	**$ 7,939**

The discount rate used to prepare the 2021, 2022 and 2023 forecast was 2.7%, which represents a decrease of 0.50% from 2020.

Regarding employee future benefits, including the Company's pension plan and OPEBs, we have compared forecast expense to support provided by the Company's actuary and have found no discrepancies. Nothing has come to our attention to indicate that the forecast for 2021 and the proposed for 2022 and 2023 are unreasonable.

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:

Table 25: Finance Charges 2019-2023

(000's)	Actual 2019	Actual 2020	Forecast 2021	Proposed 2022	Proposed 2023
Interest					
Long-term Debt	$ 35,375	$ 36,811	$ 35,452	$ 36,005	$ 34,945
Other	1,384	624	365	453	910
Amortization					
Debt Issue Expense	235	233	212	197	183
Debt Portion of AFUDC	(1,063)	(522)	(724)	(1,069)	(1,630)
Equity Portion of AFUDC	(870)	(427)	(593)	(874)	(1,333)
Total Finance Charges - Exhibit 5	**$ 35,061**	**$ 36,719**	34,712	34,712	33,075
Less: Interest on Security Deposits			(17)	(18)	(18)
Total Finance Charges - Return on Rate Base			**$ 34,695**	**$ 34,694**	**$ 33,057**
Year over year percentage change			-5.51%	0.00%	-4.72%

Finance charges proposed for 2021 are expected to decrease from 2020 by 5.51% resulting primarily from a reduction in long term debt as well as a decrease in credit facility costs. The proposed forecast for 2023 also decreased over the previous forecast years due to the expected issuance of debt on April 15, 2022 of $74,250,000 partially offset by the June 16, 2022 redemption of $28,400,000. The April 2022 issuance is expected to have a 4.25% rate whereas the June 2022 redeemed loan carries a 9% rate.

The Company has the forecast average short-term borrowing rate to be 1.24% for 2021, 1.36% for 2022, and 1.70% for 2023. We have 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.

Based upon our analysis, nothing has come to our attention to indicate that the forecast finance charges for 2021 and the proposed finance charges for 2022 and 2023 are unreasonable.

Income tax expense

Our review of income tax expense for 2019 and 2020 actuals and 2021 to 2023 forecast included:

- 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.

The following table presents the income tax expenses from 2019 to 2023:

Table 26: Income Tax Expense 2019-2023

	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023	Proposed 2022	Proposed 2023
Income Before Tax (000's)	$ 63,719	$ 65,807	$ 61,031	$ 54,060	$ 47,860	$ 76,633	$ 80,986
Income Taxes (000's)	$ 18,324	$ 19,338	$ 17,698	$ 15,384	$ 13,294	$ 22,154	$ 24,198
Effective Income Tax Rate (%)	28.76%	29.39%	29.00%	28.46%	27.78%	28.91%	29.87%
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.

The increase of approximately 2% from 2023 forecast to proposed for the effective income tax rate is due to the impact of the proposed changes of capitalization of pension costs. Further analysis is completed within the General Expenses Capitalized section of our report.

Based upon our analysis, income tax expense for forecast 2021 and proposed 2022 and 2023 appear consistent with substantively enacted corporate income tax rates and forecast increases in net income.

Intercompany charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with Order Nos. P.U. 19 (2003), P.U 32 (2007), P.U. 43 (2009), and P.U 13 (2013); and
- compared charges for 2021, 2022 and 2023 forecast to previous years and obtained explanations for unusual fluctuations and trends.

As part of the 2020 annual review, we reviewed Fortis Inc.'s methodology to estimate its recoverable expenses and noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no significant changes to the methodology in 2020.

- Fortis Inc. estimated its net pool of operating expenses for 2020 based on the 2021-2025 business plan and is billed quarterly; and
- On a quarterly basis, these expenses are subject to a true-up based on actual expenses incurred during the quarter with any true-up applied in the subsequent quarter.

The following table provides a breakdown of regulated inter-corporate charges from affiliates for 2019 and 2020, including forecast charges for 2021, 2022 and 2023:

Table 27: Charges from Affiliates including Fortis Inc. 2019-2023F

Intercompany transactions	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Charges from Affiliates including Fortis Inc.					
Trustee & Share Plan Costs	$ 27,000	$ 20,000	$ 27,000	$ 27,000	$ 28,000
Staff Charges	41,000	-	90,000	-	-
Miscellaneous	272,000	200,000	406,000	188,000	191,000
Total	**$ 340,000**	**$ 220,000**	**$ 523,000**	**$ 215,000**	**$ 219,000**
Year over year percentage change		-35%	138%	-59%	2%

Miscellaneous charges are forecast to be higher in 2021 as a result of a payment of $227,156 to Microsoft Canada Inc. paid by Fortis Inc. on behalf of Newfoundland Power.

The following table provides a breakdown of regulated inter-corporate charges to affiliates for 2019 and 2020, including forecast charges for 2021, 2022 and 2023:

Table 28: Charges to Affiliates including Fortis Inc. 2019-2023F

Intercompany transactions	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Charges to Affiliates including Fortis Inc.					
Postage	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000
Staff Charges	760,000	143,000	145,000	143,000	141,000
Miscellaneous	452,000	314,000	140,000	126,000	129,000
Total	**$ 1,214,000**	**$ 459,000**	**$ 287,000**	**$ 271,000**	**$ 272,000**
Year over year percentage change		-62%	-37%	-6%	0%

The most significant observations from our analysis of charges to affiliated companies from 2019 to 2023 are as follows:

- Staff Charges are higher in 2019 as a result of hurricane relief efforts at Maritime Electric after Hurricane Dorian and an employee on secondment to Fortis Ontario.
- Miscellaneous charges are higher in 2019 as a net result of hurricane relief efforts at Maritime Electric after Hurricane Dorian as well as incentive payments to an employee on secondment to Fortis Ontario. According to the Company 2020 charges were also higher as a result of an incentive payment to an employee on secondment to Fortis Ontario.

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.

Purchased power

We have reviewed the Company's purchased power expense forecast for 2021, 2022 and 2023 and have investigated 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 provided. Forecast purchased power expense reflects the utility rate effective on October 1, 2019 approved in Order No. P.U. 30 (2019).

Table 29: Purchased Power 2019-2023

(000's)	Actual 2019	Actual 2020	Forecast 2021	Existing 2022	Existing 2023
Purchases From Hydro	$ 456,512	$ 470,275	$ 465,872	$ 465,610	$ 461,686
DMI	(2,687)	(1,431)	(1,812)	(1,811)	(2,079)
Wholesale rate change flow-through	(8,964)	-	-	-	-
	$ 444,861	**$ 468,844**	**$ 464,060**	**$ 463,799**	**$ 459,607**
Year over year percentage change		5.39%	-1.02%	-0.06%	-0.90%

	Actual 2019	Actual 2020	Forecast 2021	Proposed 2022	Proposed 2023
Purchases from Hydro	$ 456,512	$ 470,275	$ 465,872	$ 464,811	$ 459,924
DMI	(2,687)	(1,431)	(1,812)	-	-
Wholesale rate change flow-through	(8,964)	-	-	-	-
	$ 444,861	**$ 468,844**	**$ 464,060**	**$ 464,811**	**$ 459,924**
Year over year percentage change		5.39%	-1.02%	0.16%	-1.05%

Purchased power expense is expected to increase over 2019 to 2023 due to an increase in Hydro's Utility Rate effective October 1, 2019 partially offset by declining energy sales. According to the Company, the forecast decrease is consistent with the recent decline in the provincial economy, which is attributable to a number of factors, including increased unemployment, reduced government spending, introduction of public health measures by the government to manage COVID-19 pandemic and increased number of households installing heat pumps.

Based upon our analysis, purchased power forecast for 2021, 2022 and 2023 appears consistent with billing rates from Newfoundland and Labrador Hydro effective October 1, 2019 and forecast decrease in energy sales.

Depreciation

Identified error

On August 24, 2021 the Company wrote a letter to the Board to note that during the preparation of responses to the first round of requests for information ("RFIs") an error in the Application pertaining to depreciation was identified. The Company described the error as follows:

> *"In calculating the comparative depreciation rates, each of the CIS and EV Charging Stations were inadvertently included in existing depreciation functions outlined in the 2019 Study rather than being allocated new, separate, depreciation functions corresponding with the recommended service lives for these assets. As a result, the proposed depreciation expenses contained in the Application are a result of CIS assets being depreciated over a shorter than intended service life (10 years rather than 18) and EV Charging Stations being depreciated over a longer than intended service life (30 years rather than 10)."*

On August 25, 2021 the Board responded to the letter as follows:

> *"The Board notes that the identified error relates to the calculation of test year depreciation rates for electric vehicle charging stations and the new Customer Information System, which are not expected to be in-service until 2021 and 2023 respectively. The Board's decision on the application for approval of the electric vehicle charging stations is pending. The Board's order approving the new Customer Information System (Order No. P.U. 12(2021)) is the subject of separate applications by the Consumer Advocate which are also pending – one to the Court of Appeal for leave to appeal and another to the Board for the granting of stay of the Board's decision. Considering the circumstances the Board is satisfied that the Application and the responses to RFIs do not have to be revised at this time."*

On September 15, 2021 in Order No. P.U. 29 (2021), the Board dismissed the Consumer Advocate's application for the stay of the Board's decision pertaining to the new customer information system.

As such, we acknowledge the error as described above but we have completed our review based on the Application and associated RFIs as filed and have not accounted for the error in the following analysis.

Depreciation expense

Our procedures in this section were to consider if the forecasted depreciation expense amounts, and rates incorporated in the 2022 and 2023 forecasts agree to the recommendations of the updated 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 2022 and 2023.

The following table summarizes depreciation expense, for the years from 2019 to 2023 under the 2014 Depreciation Study:

Table 30: Depreciation Expense 2019-2023

($000's)	2019A	2020A	2021F	2022F	2023F
Depreciation expense per exhibit 3	$ 62,066	$ 64,982	$ 67,739	$ 70,423	$ 74,746
Year over year change ($)	NA	2,916	2,757	2,684	4,323
Year over year change (%)	NA	4.70%	4.24%	3.96%	6.14%

The Company has indicated that the increase in depreciation expense from 2019 to 2023 is primarily due to their annual capital investment. Consistent with the Company's past practice of having an updated depreciation study filed every 4-5 years, Gannett Fleming Valuation and Rate Consultants, Inc. ("Gannett Fleming") was engaged to perform the 2019 Depreciation Study. The 2019 Depreciation Study is based on the Company's electric plant as of December 31, 2019. In the Depreciation Study, Gannett Fleming calculated deprecation rates based on the *"straight line method using the equal life group ("ELG") procedure and were applied on a whole life basis. Additionally, an* *adjustment to depreciation expense was made to amortize, over the account's remaining life, the difference between the Company's book accumulated depreciation and the theoretical reserve."* This approach is consistent with the procedures that were outlined in the 2014 Depreciation Study, which were accepted in Order No. P.U. 18 (2016).

Gannett Fleming's calculated accrued deprecation as of December 31, 2019 is $827.197 million. This is $36.956 million or 4.47 percent greater than the Company's accumulated depreciation of $790.241 million. Gannett Fleming has noted that this is within the five percent tolerance level. According to Gannett Fleming, this tolerance level is the industry's most commonly used method for adjusting depreciation. In the 2019 Depreciation Study, Gannett Fleming notes that, *"calculated accrued depreciation is used as a measure to assess the adequacy of the Company's book accumulated depreciation amount. The calculated accrued depreciation should not be viewed in exact terms as the correct reserve amount. Rather it should be viewed as a benchmark or a tool used by the depreciation professional to assess the standing of the book accumulated depreciation amount based on the most recent available information."*

Gannett Fleming refers to the difference between the calculated accrued depreciation and the book value of accrued depreciation as the reserve variance. As noted above, the reserve variance identified in the 2019 Depreciation Study is $36.956 million. Gannett Fleming has identified that the reserve variance exceeding the five percent threshold for each individual plant account is approximately $31.9 million. In the 2019 Depreciation Study, Gannett Fleming has indicated that the reserve variance which "*exceeds the five percent tolerance threshold for each individual plant amortize the reserve variance in excess of the five percent tolerance threshold over a period equal to the composite remaining life of the assets. This decreases the probability of large fluctuations in depreciation expense that can occur with relatively short amortization periods".* We have reviewed the calculation in the Gannett Fleming report supporting the $31.9 million reserve variance and have found no discrepancies. We have also recalculated the amortized reserve variance and have found no discrepancies. The treatment of the reserve variance is consistent with the 2014 Depreciation Study which was approved in Order No. P.U. 18 (2016).

The Company has proposed to implement the recommendations from the 2019 Depreciation Study as of January 1, 2022. The impact of this has been outlined in the table below:

Table 31: Summary of impact to depreciation expense

($000's)	2019A	2020A	2021F	2022F	2023F
Existing depreciation expense per 2014 Depreciation Study	$ 62,066	$ 64,982	$ 67,739	$ 70,423	$ 74,746
Impact of annual true up:					
2014 Depreciation Study (Annual True-Up)				(645)	(645)
2019 Depreciation Study (Annual True-Up) (Note 1)				1,851	1,851
Sub-total of annual true up	-	-	-	1,206	1,206
Adoption of 2019 Depreciation Study Rates (Note 2)				(674)	(699)
Sub-total impact of 2019 Depreciation Study	-	-	-	532	507
Depreciation expense	**$ 62,066**	**$ 64,982**	**$ 67,739**	**$ 70,955**	**$ 75,253**

Note 1 - The 2019 Depreciation Study impacts future depreciation expense by including the recovery of an accumulated reserve variance of approximately $1.9 million annually over the average remaining service life of the affected asset classes.
Note 2 – The 2019 Depreciation Study results in a decrease in depreciation expense of $674,000 in 2022 and $699,000 in 2023, as shown above due to the impact of new rates.

As demonstrated in the table above, the overall net impact on depreciation expense was an increase of $532,000 and $507,000 in 2022 and 2023 respectively.

Based on our review, we conclude that the depreciation rates used to calculate the proposed forecast for 2022 and 2023 agree to those recommended in the 2019 Depreciation Study and the Company's pre-filed evidence except for those previously disclosed by the Company. Therefore, with the exception of the error identified in the Company's letter dated August 24, 2021, we have concluded that the depreciation expense is calculated in accordance with the rates prescribed in the 2019 Depreciation Study.

Regulatory deferral accounts

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:

Table 32: Amortization of Regulatory Deferrals 2019-2023P

($000s)	2019	2020	2021F	2022P	2023P
2019 Hearing Costs Deferral	$ 294	$ 353	$ 353	$ -	$ -
2019 Revenue Surplus	1,752	(876)	(876)	-	-
2022 Hearing Costs Deferral	-	-	-	294	353
2022 Revenue Shortfall	-	-	-	(892)	444
Revenue Requirement Impact	**$ 2,046**	**$ (523)**	**$ (523)**	**$ (598)**	**$ 797**

Previously approved regulatory deferrals

The 2019 and 2020 actuals and forecasted 2021 amortization of regulatory deferrals consists of accounts that were previously approved by the Board as follows:

- **2019/2020 General Rate Application Costs:** 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 $1.0 million over a 34-month period commencing March 1, 2019 to December 31, 2021, with any difference between actual cost and the estimated costs to be rebated/collected through the Rate Stabilization Account. This resulted in a revenue requirement impact of $294,000 in 2019, $353,000 in 2020 and a forecasted impact of $353,000 in 2021.

- **2019 Revenue Surplus:** In Order No. P.U. 2 (2019) the Board accepted the Settlement Agreement in relation to the approval of the amortization of a forecast revenue surplus of $2,482,000 over a 34-month period, commencing March 1, 2019 and ending December 31, 2021. This represents monthly amortization of approximately $73,000 ($2,482,000/34 months). For 2019, the revenue surplus was collected net of 10 months of the approved amortization or $1,752,000 ($2,482,000 – ($73,000*10 months)). For 2020 and 2021, the amortization of the 2019 revenue surplus decreased revenue requirement by approximately $876,000 per year ($73,000*12 months).

Proposed regulatory deferrals

In the 2022/2023 General Rate Application, Newfoundland Power proposed that the Board approve the following additional regulatory deferrals for 2022 and 2023:
- amortize the recovery over a 34-month period of an estimated $1,000,000 in Board and Consumer Advocate costs related to the Application, in addition to excess costs through the RSA; and,
- amortize forecast 2022 revenue shortfall of an estimated amount of $1,262,000 over a 34-month period.

We reviewed the proposed regulatory deferrals and found:

- **2022/2023 General Rate Application Costs:** With respect to the costs relating to the 2022/2023 GRA, the Company is proposing that these costs be recovered in customer rates evenly over a 34-month period ending December 31, 2024. This is consistent with the treatment of hearing costs from the 2019/2020 GRA. This would result in an impact on the proposed revenue requirement of $294,000 in 2022, and $353,000 in each of 2023 and 2024.

- **2022 Revenue Shortfall:** Based upon a March 1, 2022 implementation, customer rates designed to recover the proposed 2022 revenue requirement would result in a $1,262,000 shortfall in the proposed 2022 revenue requirement. The Company is proposing to amortize this amount over 34-months commencing March 1, 2022 and ending December 31, 2024. This represents monthly amortization of approximately $37,000

($1,262,000/34 months). For 2022, it represents amortization over 10 months, or a reduction to revenue requirement of approximately $892,000 ($1,262,000-($36,000*10 months)). For 2023 and 2024, this represents approximately $444,000 per year.

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 Board Orders.

Conservation and demand management ("CDM") & electrification cost deferral

Conservation and demand management cost deferral account

Exhibit 12 of the current GRA provides a definition of the CDM Cost Deferral Account which is consistent with the definition approved in Order No. P.U. 13 (2013). 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.

The following table provides the forecast costs for the Company's customer conservation programs for 2021 to 2025 forecast which would be included in this deferral account:

Table 33: Customer Conservation Program Costs 2021-2025F

($000s)	2021F	2022F	2023F	2024F	2025F
General	$ 646	$ 676	$ 759	$ 842	$ 824
Program	6,530	7,170	7,006	6,305	6,560
Total	**$ 7,176**	**$ 7,846**	**$ 7,765**	**$ 7,147**	**$ 7,384**

Furthermore, the Company provided the following table which provides the breakdown of the CDM program costs for 2021 to 2025 forecast:

Table 34: Breakdown of CDB Program Costs 2021-2025F

($000s)	2021F	2022F	2023F	2024F	2025F
Regular and standby	$ 1,305	$ 1,397	$1,333	$ 1,295	$ 1,326
Temporary	54	55	-	-	-
Overtime	64	68	68	69	70
Travel	45	44	30	30	31
Miscellaneous	303	304	252	253	255
Conservation (Incentives)	2,472	2,656	2,191	2,329	2,468
Education, training, employee fees	23	22	22	23	23
Other company fees	1,126	1,562	2,135	1,430	1,414
Advertising	1,139	1,061	974	877	972
Total[1]	**$ 6,530**	**$ 7,170**	**$ 7,006**	**$ 6,305**	**$ 6,560**

Note 1 – Rounding differences in above table due to presentation.

The Company is currently proposing to continue with the 7-year amortization period for balances prior to 2021 while increasing the amortization period from 7 to 10 years for its customer CDM programs starting on January 1, 2021. In response to PUB-NP-046, the Company indicated that the previous decision to amortize the annual customer energy conservation costs over 7-years was assessed to be reasonably consistent with utility practice at the time. As a result, the Company's view is that the CDM costs prior to 2021 should continue to be amortized in accordance with the original 7-year amortization period.

The Company has indicated that the amortization period was reassessed following the Electrification, Conservation and Demand Management Plan: 2021-2025 (the Plan). The Company noted that this assessment showed that current public utility practice is to amortize CDM program costs over a 10-year period. The Company found that a 10-year period is consistent with the average life of the technologies in the Plan.

The following table summarizes the impact on revenue requirement of adopting a 10-year amortization period on CDM costs effective January 1, 2021:

Table 35: Conservation Program Costs – Forecast Deferrals and Amortizations 2021 – 2025

	2021F	2022F	2023F	2024F	2025F
7-Year Amortization Period					
Deferral	$ (6,530)	$ (7,170)	$ (7,006)	$ (6,305)	$ (6,560)
Forecast Amortization	-	933	1,957	2,958	3,859
Historical Amortization	5,890	5,256	4,596	3,568	2,603
Total Amortization	**5,890**	**6,189**	**6,553**	**6,526**	**6,462**
10-Year Amortization Period					
Deferral	(6,530)	(7,170)	(7,006)	(6,305)	(6,560)
Forecast Amortization	-	653	1,370	2,071	2,701
Historical Amortization	5,890	5,256	4,596	3,568	2,603
Total Amortization	**5,890**	**5,909**	**5,966**	**5,639**	**5,304**
Difference in Total Amortization	**$ -**	**$ (280)**	**$ (587)**	**$ (887)**	**$ (1,158)**

As noted by the Company, increasing the amortization period for CDM programs from 7-years to 10-years reduces revenue requirements in 2022 and 2023 by $280,000 and $587,000, respectively.

Electrification Cost Deferral Account

In the "Rate Mitigation Options and Impacts Muskrat Falls Report" dated February 7, 2020 it is noted that the *"co-ordination of the development of a comprehensive electrification potential plan including electrification and conservation demand management programs to be finalized by the utilities and submitted to the Board in 2021".*

According to information filed with the Application, the Company and NL Hydro developed the *Electrification, Conservation and Demand Management Plan: 2021-2025* which continues previous customer CDM programs while introducing new customer electrification programs. On December 16, 2020 the Company filed the *"2021 Electrification, Conservation and Demand Management Application" ("2021 ECDM Application")* which remains under review with the Board.

As a result of these new electrification initiatives the Company proposed the definition of the Electrification Cost Deferral Account in Exhibit 13 as follows:

> *"This account shall be charged with the costs incurred in implementing the Customer Electrification Program Portfolio. These costs include: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, program evaluation costs and the costs to operate Company-owned charging stations. This account shall also be charged the costs of major studies such as pilot programs, comprehensive customer surveys and potential studies that cost greater than $100,000. This account shall be credited with the receipt of government funding related to electrification programs and any revenues associated with the operation of Company-owned charging stations. The account will exclude any*

expenditure properly chargeable to plant accounts. The account shall also exclude electrification expenditures that are general in nature and not associated with a specific electrification program, such as costs associated with providing electrification awareness, and general planning, research and supervision costs. Transfers to, and from, the proposed account will be tax-effected. This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred. Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Clause or as otherwise ordered by the Board."

The Company has forecasted electrification program costs as follows:

Table 36: Electrification Programs Costs 2021F-2025F

($000s)	2021F	2022F	2023F	2024F	2025F
General	$ 136	$ 210	$ 187	$ 199	$ 219
Program	1,336	3,014	3,944	4,494	4,385
Total	**$ 1,472**	**$ 3,224**	**$ 4,131**	**$ 4,693**	**$ 4,604**

The following table provides the breakdown of the program costs related to the electrification programs forecast from 2021 to 2025:

Table 37: Program Costs Breakdown - Electrification Programs 2021F-2025F

($000s)	2021F	2022F	2023F	2024F	2025F
Residential EV & Charging Infrastructure Program	$ 446	$ 978	$ 1,769	$ 1,921	$ 2,776
Commercial EV & Charging Infrastructure Program	238	361	458	563	802
Custom Electrification Program	149	273	221	333	322
Make Ready	29	70	124	181	237
EV Demand Response Pilot Program	-	508	277	220	-
Custom Fleet Pilot Program	295	605	857	1,037	-
Electric Vehicle Charging Network (O&M)	179	219	238	239	248
Total	**$ 1,336**	**$ 3,014**	**$ 3,944**	**$ 4,494**	**$ 4,385**

The Company has proposed amortizing electrification program cost forecasted for 2021 to 2025 over ten years. The resulting annual amortization cost has been outlined below:

Table 38: Electrification Program Costs – Forecast Deferrals and Amortization 2021F-2025F

($000s)	2021F	2022F	2023F	2024F	2025F
Deferral	$ (1,336)	$ (3,014)	$ (3,944)	$ (4,494)	$ (4,385)
Forecast Amortization	-	134	435	829	1,279

In response to PUB-NP-048 the Company provided a summary of various recovery periods for electrification costs. This response referenced the following examples:

- Consumers Energy in Michigan recovers pilot program costs over 5 years;
- Xcel Energy in Colorado recovers program costs over 10 years;
- EV program costs in Maryland are recovered over 5 years;
- Utilities in New York recover costs for make ready charging infrastructure for EVs over 15 years;
- Rebates for EV chargers are recovered over 10 years in New Mexico; and
- Rebates for EV chargers are recovered over 10 years in Oregon.

Furthermore, in the 2019 Depreciation Study Gannett Fleming also recommended a 10-year average service life for EV charging stations.[5]

We have reviewed the Company's CDM Cost Deferral Account and the Electrification Cost Deferral Account and have noted no errors in the forecast amortization. During our review we noted that the Company's proposed change in amortization period to 10-years is to be applied to costs commencing January 1, 2021. Historically deferred balances are continuing to amortize over a 7-year period. The 2021 ECDM Application remains under review by the Board.

[5] 2019 Depreciation Study page I-6

Capital expenditures

We have reviewed the significant variances from 2019 to 2020 as part of our annual financial reviews and our comments on these variances are contained in our annual review reports filed with the Board.

The following table and graph below details:

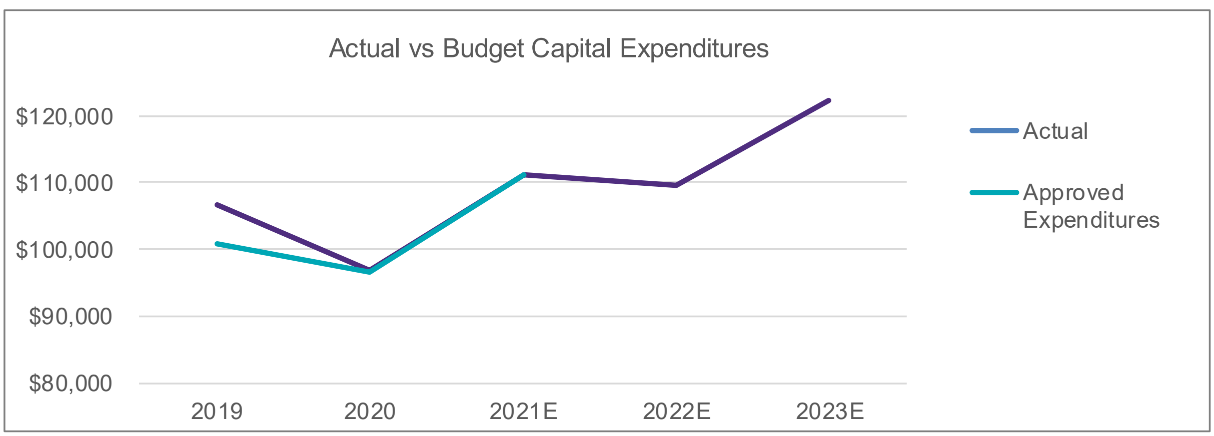
- the actual versus budget capital expenditures from 2019 to 2020, and the forecast figures for 2021 to 2023; and
- demonstrates that in 2019 the Company was over budget by 5.67% on capital expenditures and for 2020 the Company was over budget by 0.39% on capital expenditures.

Table 39: Capital Expenditures 2019-2023 Existing

($000's)	**2019**	**2020**	**2021E**	**2022E**	**2023E**
Actual (a)	$ 103,417	$ 85,447	$ 111,190	$ 109,651	$ 122,321
Actual Carry Over (a)	3,154	11,539	-	-	-
	$ 106,571	$ 96,986	$ 111,190	$ 109,651	$ 122,321
Approved Expenditures (b)	$ 100,856	$ 96,614	$ 111,298	N/A	N/A
Over (Under) Budget	5.67%	0.39%	-0.10%	N/A	N/A

(a) The figures for 2019 and 2020 represent actual expenditures approved in that year and carry over expenditures from projects approved in previous years. 2021, 2022 and 2023 are forecasted based on the Company's existing Capital Budget Plans. However, we have noted that electrification expenditures in 2021 are currently under review by the Board and the 2022 Capital Budget Application, which includes electrification expenditures, is also under review by the Board.

(b) 2022 Capital Plan is currently submitted by the Company and awaiting approval by the Board, amounting to $109,651,000.



In Order No. P.U.12 (2021) the Board approved expenditures of $111,298,000 for the 2021 capital program. This represents an increase of approximately 15.2% compared to the 2020 approved capital expenditures of $96,614,000.

The increase over the forecast period is primarily observed in the Distribution and Information Systems categories of capital expenditure. Distribution capital expenditure is forecast to average approximately $48.3 million annually from 2021 to 2023, compared to the average of approximately $45.8 million annually in 2019 and 2020. This is due to the Company's multi-year LED Street Lighting Replacement Plan commencing in 2021. Information Systems capital expenditure is forecast to average approximately $16.0 million annually from 2021 to 2023, compared to an average of approximately $7.4 million annually in 2019 and 2020. Capital expenditures for information systems includes the replacement of Newfoundland Power's Customer Service System which commences in 2021.

According to the Company, annual capital programming continues to focus efforts on refurbishment of assets to extend their useful service lives and replacement of assets that can no longer provide safe and reliable service to customers. Over 50% of the Company's forecasted capital expenditures relate to the replacement or refurbishment of existing assets. In the Company's response to PUB-NP-010 Newfoundland Power further explains the consideration it applies in managing capital expenditures required for plant replacement such as assessment of alternative coordination of capital projects and deferral of capital projects.

The Company is proposing forecast capital expenditures of $109,651,000 for 2022 which is a decrease of 1.38% in comparison to the approved capital expenditures in 2021. The Company is also proposing forecast capital expenditures of $122,321,000 for 2023, which is an increase of 11.55% in comparison to the proposed forecast for 2022. Capital expenditures for 2021 through 2023 are based on the 2022 Capital Budget Application filed on May 18, 2021, adjusted for known carryovers.

In response to PUB-NP-047 Newfoundland Power provides a proforma revenue requirement analysis of the Company's Electrification Initiatives, which include details on its capital costs over the 2021 to 2023 forecast years. The capital costs proposed for Electric Vehicle Charging Network (Pooled) project are $1,538,000, $1,530,000, and $460,000 for 2021, 2022 and 2023 respectively.

Non-regulated expenses

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

- assess the Company's compliance with Board Orders; and
- compared non-regulated expenses for the 2021, 2022 and 2023 forecast to prior years and investigated any unusual fluctuations.

Table 40: Non-regulated Expenses 2019-2023

(000's)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Labour Costs	$ 1,168	$ 1,660	$ 1,152	$ 791	$ 925
Intercompany Charges	2,031	2,251	1,967	2,234	2,300
Community Relations and Other	368	220	315	320	326
Corporate Advertising	10	1	10	10	10
Non-regulated Expenses Before Tax	3,577	4,132	3,444	3,355	3,561
Less: Income Taxes	1,073	1,240	1,033	1,007	1,068
Non-regulated Expenses After Tax	**$ 2,504**	**$ 2,892**	**$ 2,411**	**$ 2,348**	**$ 2,493**

The 2021, 2022 and 2023 non-regulated expenses have been forecast at $3,444,000, $3,355,000, and $3,561,000 (before tax) respectively, as compared to $4,132,000 in 2020.

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 2022 and 2023, 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 is also in compliance with Order No. P.U. 18 (2016) related to the earnings performance measure as the Company has classified the STI payout at 50% of target for non-regulated. However, it should be noted that this Order was issued prior to the replacement of the regulatory performance measure with the cash flow performance measure.

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.

General expenses capitalized ("GEC")

On August 14, 2020, the Company filed with the Board a 'Review of Capitalization Policies and Guidelines' (the "Report"). On February 16, 2021, the Board acknowledged that the Company's GEC methodology was last considered by the Board in 1999 and should be revisited. The Board requested that the Company include a review of its methodology and cost ratios used to determine GEC with its next Application. The Board also requested that the review address why the Company is the only utility surveyed that includes pension costs in its GEC and the potential impact on revenue requirement and customer rates if the Company capitalized pension costs by way of a labour loader. In the GRA the Company filed a report titled 'Review of General Expenses Capitalized' in Volume 2: Supporting Materials ("GEC report").

Our procedures in relation to the GEC included the following:

- reviewed the Company's *"Review of General Expenses Capitalized"* report included in the Application;
- considered the proposed revisions to the GEC ratios and adjustments to general expenses categories to be effective as of January 1, 2023;
- considered the proposal to remove pension costs from the GEC calculation and directly charge pension costs to capital projects by way of a labour loader, effective January 1, 2023; and
- reviewed the revenue requirement impacts over the rate setting period.

GEC methodology

The Company historically follows the incremental cost method to allocate general expenses to GEC. The use of this method was approved by the Board in Order No. P.U. 3 (1995-96) (the "GEC Order"). Based on the *"Survey of Capitalization Practices of Canadian Utilities"* prepared by the Company, which included eleven respondents, five utilities use the full cost method, two utilities use the incremental cost method, one utility uses a burden rates method, while three utilities responded not applicable.

The Company has presented two methodologies that can be applied when capitalizing general expenses as follows:

1) Incremental Cost Method – capitalized only those general expenses that are incremental to a utility as a result of its capital program.
2) Full Cost Method – capitalized any general expenses incurred in connection with a capital program, including expenses that benefit both a utility's operations and its capital program.

During the request for information process of this Application, the Board asked the Company *"why does Newfoundland Power propose continuing with the incremental method when the full cost methodology appears to be a more common practice among the utilities surveyed?"*[6] In response to this question, the Company provided the following:

"First, the Company considered the regulatory principle of customer rate stability. Stability in GEC amounts is conducive to stability in customer rates. The incremental cost method results in reasonably stable GEC amounts on a year-over-year basis. Annual GEC amounts were more variable under the full cost method.

Second, Newfoundland Power considered the regulatory principle of intergenerational equity. The full cost method capitalizes any general expenses incurred in connection with a capital program. The incremental cost method capitalizes only those general expenses that are incremental to a utility as a result of its capital program, with other costs expensed as incurred. This ensures costs are recovered only from customers who benefit from the service provided by capital assets.

Third, the Company considered the results of the Survey of Capitalization Practices of Canadian Utilities. Notably, Newfoundland Power considered the methodology used by the utilities as well as their overall capitalization rate.

While the responses varied, the Company's use of the incremental method has resulted in its overall capitalization rate being comparable to that of the surveyed utilities. Excluding pension costs, Newfoundland Power's overall capitalization rate was approximately 9% in 2019 compared to an average of 10% of the surveyed utilities. Ensuring capitalization amounts are comparable to other utilities is consistent with the Board's findings in Order No. P.U. 3

[6] PUB-NP-058

(1995-96). Based on this review, use of the incremental cost method to allocate general expenses to GEC continues to be appropriate."

We considered the Company's position and have found the following:

1) **the proposed incremental cost method is an acceptable methodology to determine the GEC;**
2) **this proposal is supported by the Company's survey results; and**
3) **the GEC results have been consistent year over year.**

GEC - General expenses and ratios review

The following table summarizes the existing and revised GEC ratios, in addition to the revenue requirement impact for 2023 forecast:

Table 41: GEC Ratios and Amounts

($000's)	Existing Ratios	2023E	Revised Ratios	2023P
Construction Activities				
Capital Planning	Direct	$ -	Direct	$ -
Operating Supervision	15%	601	15%	717
Tools, Equipment and Safety Clothing	48%	788	65%	1,068
System Operations	Direct	-	10%	236
Non-Construction Activities				
Finance	13%	263	10%	202
Human Resources	13%	299	10%	243
Information Systems	-	-	10%	345
Employee Welfare[1]	31%	41	-	-
Printing Services	13%	36	-	-
Indirect GEC[2]		2,028		2,811
Direct GEC[3 4]		1,559		875
Total GEC		$ 3,587		$ 3,686
Revenue Requirement Impact				**$ (99)**

1 - Newfoundland Power has proposed to include this category under Human Resources at 10% as a specific ratio could not be determined.
2 - indirect GEC are allocations that are considered incremental as a result of the capital program. These are comprised of construction activities, non-construction activities and pension.
3 - direct GEC consists of employees deemed incremental as a result of the capital program, primarily employees whose focus is on capital planning and standards as it does not relate to a specific asset.
4 - according to the Company, the reason for the $684,000 decrease from existing to proposed is due to the proposal of System Operations to be included in indirect GEC as opposed to direct GEC.

The Company's review of the GEC confirmed that all general expenses included in the GEC calculation remain appropriate, except for those related to printing services. Furthermore, the review indicated that general expenses related to information systems should be added to the GEC calculation, similar with general office activities whereby there would be lower work requirements associated with information systems if there was no capital program. Overall, the Company noted that all proposed general expenses to be included in the GEC calculation are consistent with the definition of Capitalized Overheads in the Federal Energy Regulatory Commission ("FERC") System of Accounts. The Company's review of its General Expenses is included as Appendix A of the GEC report.

The GEC review also considered the ratios applied in allocating amounts to GEC and the Company's proposed changes are to account for their operations since the matter was last considered by the Board in 1999. The Company's review of its ratios is included as Appendix B of the GEC report.

As a result of the Company's ratio and general expenses review, the following proposed changes to the calculation of GEC will reduce the Company's 2023 revenue requirement by approximately $0.1 million.

<u>Printing services</u>
The Company is proposing that general expenses associated with this activity be removed from GEC. According to the Company, while activity may vary, the reduction in general expenses would be small if there were no capital program.

<u>Information systems</u>
The Company is proposing that general expenses associated with this activity are included within GEC. According to the Company, with no capital program there would be lower work requirements associated with planning information systems related solutions, including software enhancements and upgrades. There would be lower work requirements associated with providing technical support given the reduction in employees and thus personal computers.

General expenses associated with these activities are proposed to be added to the GEC calculation at a 10% ratio. In addition, if there were no capital program there would be no general implementation expenses associated with specific capital projects being implemented. General implementation expenses can be directly charged to the specific information system capital project. Therefore, these costs do not need to be included in the GEC calculation.

<u>Tools, equipment, and safety clothing</u>
The Company is proposing that a ratio of 65% compared to the historical 48% of tools, equipment and safety clothing general expenses is appropriate since these costs would be lower if there was no capital program. The existing 48% ratio reflects the percentage of the Company's regional labour that was related to capital work in 1999. According to the Company, the percentage of Newfoundland Power's regional labour related to capital work is 65% in 2020.[7]

Furthermore, the Company explains that the 65% includes 54% in labour charged to capital projects and 11% in labour charged to retirement projects, which reflects the amount of time associated with removing plant from service.[8]

<u>System Operations</u>
The Company is proposing that a ratio of 10% of system operations general expenses is appropriate and justifies it based on the reduction of 2 FTEs in this area if there was no capital program. The Board asked to explain what has changed in the Company's rationale in determining the appropriate cost ratio for this cost category since Order No. P.U. 3 (1995-96). The Company provided the following response:

"…Based on the lower work requirements, if there were no capital program, it would be possible to reduce 1 PSO on each shift, or 4 PSOs in total. Both the existing and revised ratios reflect this reduction. However, given the practicalities of worker requirements for vacation and unplanned leave, it was determined that 2 relief workers would be added to the SCC to ensure proper staffing could be maintained 24 hours a day.

The net reduction of 2 full-time equivalents in the SCC represents a reduction of approximately 10% in the operating costs for system operations.

Accordingly, it is the Company's view that applying a GEC ratio for system operations of 10% is appropriate."[9]

<u>Non-Construction activities</u>
The Board asked the Company why they are proposing to adjust the rate to 10% from the 13% for its non-construction activities that has been in place since 1999 and to provide the impact on revenue requirement, rate base and rates if this percentage did not change to 10%. The following response was provided by the Company:

"In the Company's view, the use of a nominal rate of 10%: (i) recognizes there would be some reduction in general expenses related to non-construction activities if the capital program were eliminated; and (ii) reasonably addresses the practical limitations associated with quantifying a specific reduction in these general expenses if the capital program were eliminated. Order No. P.U. 3 (1995-96) confirmed the reasonableness of applying a 10% nominal rate.

If the existing ratio of 13% was applied to general expenses related to non-construction activities, rather than the 10% ratio, the amount allocated to GEC would be approximately $0.2 million higher in 2023. The Company's revenue

[7] Review of General Expenses Capitalized report – page 8 of 13
[8] Review of General Expenses Capitalized report – page 8 of 13, footnote 26
[9] PUB-NP-063

requirement would decrease by $0.2 million, with a corresponding increase in rate base of $0.2 million. The customer rate impact would be a reduction of 0.03%."[10]

NL Hydro asked the Company what aspects of Order No. P.U. 3 (1995-96) has the Company relied upon to determine that a nominal rate of 10% is appropriate for finance, human resources, and information systems. Furthermore, NL Hydro asked to explain in detail how the existing ratio of 13% for finance and human resources was calculated. In addition, NL Hydro asked for detail on why this calculation can no longer be completed as noted in the response to NLH-NP-019. The Company provided the following response:

"…The Board accepted a nominal rate of 10% as a reasonable proxy to allocate a portion of printing costs to GEC. The concept of a nominal rate was then applied to allocate a portion of finance and human resources costs to GEC.

…The nominal rate of 13% for non-construction activities reflects the rate used by Newfoundland Power at the end of the phase-in period in 1999, [as a proxy percentage was used, there is no calculation to provide.]"[11]

Pension capitalization

The Company's GEC calculation currently includes 46% of current service costs associated with its pension plans, in accordance with Order No. P.U. 2 (2019). The Company is proposing to continue using 46% as the percentage allocation of current services costs associated with its pension costs but by applying a labour loader. The 46% is based upon a review by the Company of the unloaded labour, of which capital has ranged from 45% to 47% for the period of 2016 through 2020 and is 46% on a five-year average. The percentage allocation is calculated and reviewed annually based upon actual labour costs in that year.

The loading rate to apply pension to labour is estimated by dividing total current service pension expense by total base labour for each year. Base labour is equal to salary costs of internal employees only.

Applying a labour loader would result in a more accurate allocation of general expenses to capital projects because it would follow the labour that is directly charged to a capital project. In contrast, the GEC calculation uses a flat rate to allocate the total GEC amount across capital projects. The use of a labour loader to directly charge pension costs to capital projects is consistent with current utility practice. Based on the survey in the Capitalization Practices Report of Canadian Utilities, ten of the eleven responding utilities capitalize pension costs by way of a labour loader. Therefore, according to the Company removing pension costs from the GEC calculation and directly charging pension costs to capital projects by way of a labour loader is consistent with sound public practice and the treatment of the Company's OPEB costs. Other benefits of using a labour loader are discussed in response to PUB-NP-059 including compliance with US GAAP without a regulatory approval and reduced administration. We reviewed the PUB-NP-059 and take no exception to the benefits described.

[10] PUB-NP-064
[11] NLH-NP-093a

The Company is proposing to implement this change effective January 1, 2023 and the following table presents the revenue requirement impact of $Nil due to this change:

Table 42: Pension Costs Capitalization

($000's)	2023P
Changes in GEC	
Operating Costs[1]	$ 3,388
Employee Future Benefits Costs	(3,388)
Revenue Requirement Impact	**$ -**

Note 1 –Excludes the $0.1 million revenue requirement decrease relating to the proposed GEC ratio and general expenses changes.

The increase in operating costs and decrease in employee future benefits costs of $3,388,000 relates to the proposed change of using a labour loader instead of GEC allocation method to capitalize pension costs. Although the labour loader will have a $Nil impact on the 2023 revenue requirement, directly charging pension costs to capital projects by way of labour loader will increase the 2023 revenue requirement due to income tax effects. For income tax purposes, GEC is recognized as an expense in the year incurred, resulting in a tax deduction in the initial year of the GEC calculation. Therefore, by removing pension costs from the GEC calculation, the associated tax deduction for this portion of GEC will no longer exist in 2023. The annual depreciation expenses for this portion of GEC will also no longer exist in subsequent years.

The following table provides the change in 2023 revenue requirements based on capitalizing pension costs by way of a labour loader:

Table 43: Pension capitalization – Labour loader

($000's)	2023P
Pension Costs - General Expenses	$ -
Income Taxes - Changes in Pension Capitalization	999
Change in 2023 Revenue Requirement Before Income Taxes	**999**
Income Taxes - Change in Revenue Requirement	428
Total Change in 2023 Revenue Requirement	**$ 1,427**

Capitalizing pension costs by the way of a labour loader will remove approximately $3.4 million (Table 42) in pension costs from the GEC in 2023, in turn removing the tax deduction. This will increase income taxes included in the 2023 revenue requirement by approximately $1.0 million as seen in the table above. This increase in revenue requirement will be subject to taxation, therefore the total increase in revenue requirement in 2023 is approximately $1.4 million. With the removal of pension costs from GEC the associated annual add back for depreciation expense will also not exist. In turn, this will decrease revenue requirements in each subsequent year having no impact on revenue requirement over the total lives of the related capital assets. We agree with the income tax treatment and income tax effects on revenue requirement regarding the proposed change to a labour loader.

Based on our review of the pension capitalization, the allocation of pension costs directly to capital projects by way of a labour loader is consistent with the Company's *"Survey of Capitalization Practices of Canadian Utilities" report*. Furthermore, the income tax effects in relation to the pension cost allocation is appropriate based on our review and calculations.

Summary revenue requirement impacts of GEC Review

The following table provides the summary of impacts to the 2023 revenue requirement as a result of the GEC review proposed within this Application:

Table 44: 2023 Revenue Requirement Impacts

($000's)	2023P
GEC Calculation	$ (99)
Labour Loader	-
Income Taxes	1,427
Total Revenue Requirement Increase	**$ 1,328**

Other considerations

In the Application the Company is proposing to include the $1.4 million revenue requirement increase in 2023. The Board questioned if the Company considered the possibility of using a mechanism such as a deferral account to smooth the $1.4 million impact on revenue requirement for the 2023 test year over a period of three to five years or longer. The Company provided the following response:

> *"The $1.4 million impact on 2023 revenue requirement associated with the proposed change in capitalizing pension costs will reverse over time, reducing revenue requirement in future years. As the impact is timing related rather than recovery of cost (e.g. hearing costs), the Company did not consider the use of a deferral account to minimize the impact on 2023 revenue requirement.*
>
> *However, in Newfoundland Power's view, employing a deferral account is a reasonable alternative to smooth the impact on 2023 revenue requirement. The Board has, in the past, permitted the use of cost recovery deferrals and amortizations where it determines the circumstances justify such treatment of utility costs."*[12]

The Company also provided the following table to demonstrate three amortization period scenarios and the impact on the 2023 revenue requirement and customer rates, based on amortization to begin on January 1, 2023: [13]

Table 45: 2023 Revenue Requirement - Deferral and Amortization Scenarios

($000's)	Proposed	3 Years	5 Year	10 Year
Change in pension capitalization	1,427	1,427	1,427	1,427
Deferral	-	(1,427)	(1,427)	(1,427)
Amortization	-	476	285	143
Return on rate base and income tax effects	-	24	29	32
Pro forma 2023 revenue requirement impact	**1,427**	**500**	**314**	**175**
Pro forma customer rate impact	**0.20%**	**0.07%**	**0.04%**	**0.02%**
Remaining recovery[1]	**-**	**951**	**1,142**	**1,284**

1 - This line demonstrates the remaining balance to be recovered after December 31, 2023.

Without a deferral mechanism the proposed pension capitalization would result in a $1.4 million impact to 2023 revenue requirement. The Board could consider smoothing the impact of the adjustment on ratepayers through a multi-year amortization period.

[12] PUB-NP-060
[13] Rate impact - PUB-NP-110

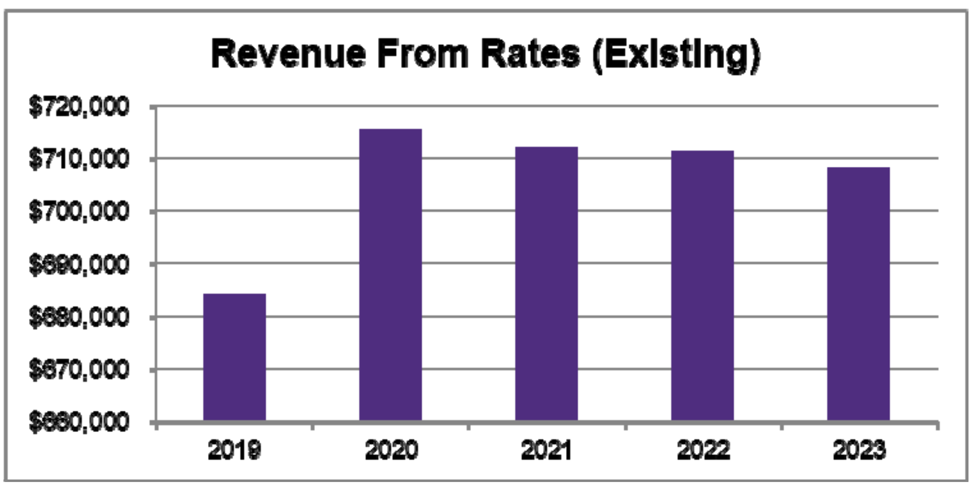
Proposed forecast revenue

Revenue from rates

We have compared the actual revenues for 2019 and 2020 to the forecast revenues using existing rates for 2021 to 2023 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 May 2021. The results of this analysis by rate class are as follows:

Table 46: Existing Revenue from Rates 2019-2023F

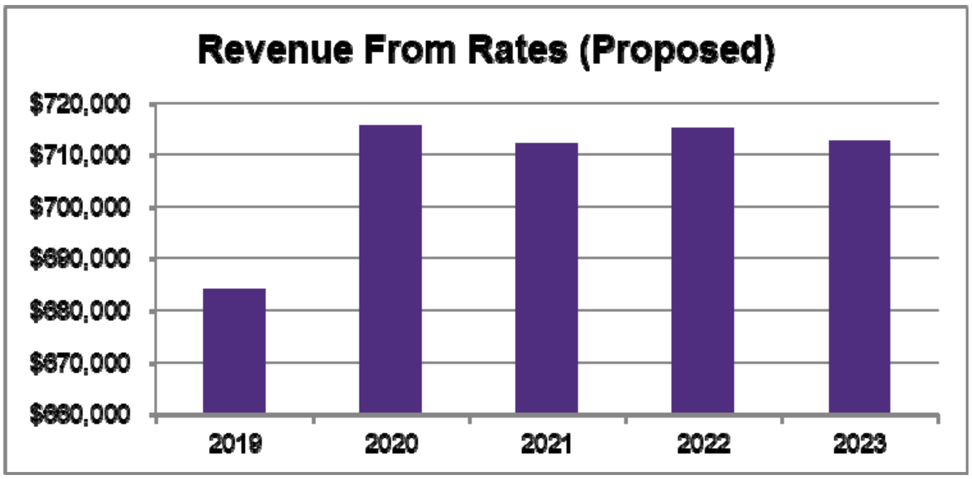
(000's)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Residential	$ 432,272	$ 458,433	$ 452,634	$ 446,770	$ 444,077
General Service					
0-100 kw	93,038	93,282	94,866	98,082	98,332
110-1000 kva	101,397	105,418	108,816	109,004	108,865
Over 1000 kva	37,916	38,643	36,354	38,092	37,665
Streetlighting	16,664	16,983	16,942	16,761	16,614
Discounts Forfeited	2,892	2,868	2,726	2,853	2,845
Revenue From Rates	$ 684,179	$ 715,627	$ 712,338	$ 711,562	$ 708,398
Year over year % change		4.60%	-0.46%	-0.11%	-0.44%



The table below summarizes the actual revenues for 2019 and 2020 to the forecast revenues using proposed rates for 2022 to 2023 to assess any significant trends:

Table 47: Proposed Revenue from Rates 2019-2023P

(000's)	Actual 2019	Actual 2020	Forecast 2021	Proposed 2022	Proposed 2023
Residential	$ 432,272	$ 458,433	$ 452,634	$ 448,930	$ 446,467
General Service					
0-100 kw	93,038	93,282	94,866	98,657	99,063
110-1000 kva	101,397	105,418	108,816	109,679	109,709
Over 1000 kva	37,916	38,643	36,354	38,337	37,958
Streetlighting	16,664	16,983	16,942	16,892	16,743
Discounts Forfeited	2,892	2,868	2,726	2,869	2,863
Revenue From Rates	$ 684,179	$ 715,627	$ 712,338	$ 715,364	$ 712,803
Year over year % change		4.60%	-0.46%	0.42%	-0.36%



The Company's revenues have been fluctuating by various percentages since 2019. We noted the following reasons for the changes in the revenue levels from 2019 to 2023:

- The 4.60% increase in 2020 over 2019 was primarily due to higher wholesale electricity rates effective October 1, 2019. These factors were partially offset by the impact of lower electricity sales.
- The 2021 forecast decrease in revenues using existing rates in effect is 0.46% less than 2020 due to the decrease in energy sales of 0.16%.
- The 2022 forecast decrease in revenues using existing rates in effect is 0.11% under the 2021 forecast. Under the new rates proposed in this Application, the revenues for 2022 are forecast to increase 0.42% over 2021 forecast, which is primarily a result of the proposed rate increase of 0.8%.
- The 2023 forecast decrease in revenues using existing rates in effect is 0.44% less than the 2022 forecast. Under the new rates proposed in this Application, the decrease in revenues for 2023 from proposed 2022 is 0.36%, which is primarily a result of the decrease in energy sales of 0.65% from 2022 to 2023 forecast.

The number of customers and the GWhs sold to these customers for 2019 and 2020 and forecast 2021 to 2023 and proposed 2022 and 2023 are as follows:

Table 48: Customers and Electricity Sold 2019-2023

	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Customers	269,045	270,285	271,298	272,253	273,165
% Change		0.46%	0.37%	0.35%	0.33%
GWh Sold	5,847	5,729	5,720	5,703	5,670
% Change		-2.02%	-0.16%	-0.30%	-0.58%

	Actual 2019	Actual 2020	Forecast 2021	Proposed 2022	Proposed 2023
Customers	269,045	270,285	271,298	272,253	273,165
% Change		0.46%	0.37%	0.35%	0.33%
GWh Sold	5,847	5,729	5,720	5,699	5,662
% Change		-2.02%	-0.16%	-0.37%	-0.65%

Source: Tables 1-1 and 5-3 of pre-filed evidence.

As the above table indicates, from 2019 to 2020 the number of customers increased by 0.46%. This trend is forecasted to continue to increase for 2021 to 2023 forecast with an annual increase of 0.37%, 0.35%, and 0.33%, respectively.

GWhs sold by the Company decreased by 2.02% from 2019 to 2020. Under existing rates, the Company has forecast a decline of 0.16%, 0.30% and 0.58% for 2021, 2022, and 2023 respectively.

Although the number of customers is expected to increase by an average of 0.4% per year over the period from 2019 to 2023, GWhs sold is expected to decrease primarily as a result of an expected decrease in domestic average use. According to the Company, the sales to domestic service customers are forecast to decline by approximately 1.0% annually from 2019 to 2023 which reflects the challenging economic conditions in the service territory, as well as the penetration of heat pumps among the Company's customers which has increased from approximately 4% in 2014 to approximately 18% in 2020. Energy sales in 2020 were also affected by public health measures introduced by the Provincial Government to manage the COVID-19 pandemic. These public health measures have continued into 2021 but are expected to subside throughout the year. Energy sales in 2022 and 2023 are not expected to be affected.

In reviewing the 2021 to 2023 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.

Based on our procedures nothing has come to our attention to indicate the forecast revenues from rates for 2021, 2022 and 2023 appear unreasonable.

Other revenue

The Company's other revenue for 2019 and 2020 and forecast for 2021, 2022, and 2023 is as follows:

Table 49: Other Revenue 2019-2023

($000s)	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023
Pole Attachment	$ 2,275	$ 2,507	$ 2,639	$ 2,475	$ 2,483
Provisioning Work	2,280	1,834	1,391	1,335	1,318
Customer account interest	1,335	1,292	1,250	1,292	1,277
Interest on RSA	(134)	(176)	(1,133)	(1,807)	(1,798)
Wheeling Charges	765	753	776	753	722
Miscellaneous	1,378	1,016	728	698	677
Total	**$ 7,899**	**$ 7,226**	**$ 5,651**	**$ 4,746**	**$ 4,679**
Year to year % change		(8.52%)	(21.80%)	(16.01%)	(1.41%)

($000s)	Actual 2019	Actual 2020	Forecast 2021	Proposed 2022	Proposed 2023
Pole Attachment	$ 2,275	$ 2,507	$ 2,639	$ 2,475	$ 2,483
Provisioning Work	2,280	1,834	1,391	1,335	1,318
Customer account interest	1,335	1,292	1,250	1,292	1,277
Interest on RSA	(134)	(176)	(1,133)	(629)	-
Wheeling Charges	765	753	776	753	722
Miscellaneous	1,378	1,016	728	698	673
Total	**$ 7,899**	**$ 7,226**	**$ 5,651**	**$ 5,924**	**$ 6,473**
Year to year % change		(8.52%)	(21.80%)	4.83%	9.27%

The tables above indicate the following variances:

- Pole attachment: the increase in pole attachment revenue for 2021 compared to 2020 reflects a one-time adjustment to balance the amount owing to Bell Aliant in accordance with the Joint Use Agreement. The forecast pole attachment revenue for 2022 and 2023 does not include this one-time adjustment.

- Provisioning Work: the increase in provisioning work in 2019 and 2020 is attributable to network upgrade initiatives undertaken by telecommunications providers according to the Company.

- Interest on RSA: the increase in interest expense on RSA from 2019 to 2023 forecast according to the Company is mainly due to the forecast transfers related to the Energy Supply Cost Variance Reserve ("ESCVR"). The negative ESCVR transfers reflect lower forecasted demand and energy supply costs in 2022 and 2023 compared to what is currently included in 2020 Test Year Rates. The ESCVR transfers reduce the forecast balance in the RSA account by approximately $24.3 million in 2022 and $26.7 million in 2023.

- Miscellaneous: according to the Company, the decrease in miscellaneous charges is due to the interest charges associated with customer financing programs and contributions in aid of construction. The 2019 and 2020 figures included one-time items that are not anticipated to continue such as the property disposition and standby generation for Newfoundland and Labrador Hydro.

Based on our procedure nothing has come to our attention to indicate the forecast other revenues for 2021, 2022 and 2023 appear unreasonable.

Proposed revenue from rates

The Company is proposing that the Board approve rates, tolls, and charges effective for service provided on and after March 1, 2022, to provide an average increase by class in electrical rates of 0.8%, based upon:

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

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

c) a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in paragraphs 14 of the Application, of $715,364,000 for 2022 and $712,803,000 for 2023.

We have reviewed the Company's proposed rates effective March 1, 2022. Specifically, the procedures we have performed include the following:

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

In Exhibit 11 of the GRA the Company provides a comparison of October 1, 2019 existing rates, the rates in effect at the date of the GRA filing, to March 1, 2022 proposed rates. Since the filing of the GRA, the Board has approved customer rates effective July 1, 2021 in Order No. P.U. 23 (2021). In response to PUB-NP-004 the Company indicated that the July 1, 2021 customer rate increase of 2.5% has no material impact on the average increase in customer rates proposed in the GRA of 0.8%. The energy sales forecast incorporated in the GRA reflected an increase of 3% related to the July 1, 2021 rate increase. While no quantification was provided of the customer rate impact, we understand from discussion with the Company officials that the difference of 0.5% in a customer rate increase would have no material impact to energy sales forecast including elasticity effects and thus there would be no material impact on the proposed customer rate increase of 0.8%.

The March 1, 2022 proposed customer rates presented in Exhibit 11 do not reflect the July 1, 2021 rates and consequently do not reflect the 2.5% customer rate increase approved in Order No. P.U. 23 (2021). Newfoundland Power would incorporate this approved increase, already reflected in existing July 1, 2021 customer rates, in the determination of the Company's final customer rates in a subsequent compliance application.

The following table compares October 1, 2019 rates to March 1, 2022 proposed rates by class including RSA and Municipal Tax Adjustment ("MTA"):

Table 50: Existing and Proposed Rates, Tolls & Charges

	EXISTING RATES October 1, 2019		PROPOSED RATES March 1, 2022		CHANGE ($)	CHANGE (%)
DOMESTIC						
Total Customers for Class (000's)	234,132		237,088		2,956	1.26%
DOMESTIC - RATE # 1.1						
Basic Customer Charge (Monthly)						
Not Exceeding 200 AMP service	$15.97		$16.10		$0.13	0.81%
Exceeding 200 AMP Service	$20.97		$21.10		$0.13	0.62%
Energy Charge - All Kilowatt Hours (Cents/kWh)	$0.12203		$0.12298		$0.00095	0.78%
Minimum Monthly Charge						
Not Exceeding 200 AMP service	$15.97		$16.10		$0.13	0.81%
Exceeding 200 AMP Service	$20.97		$21.10		$0.13	0.62%
Prompt Payment Discount	1.50%		1.50%		-	-
DOMESTIC - RATE # 1.1S						
Basic Customer Charge (Monthly)						
Not Exceeding 200 AMP service	$15.97		$16.10		$0.13	0.81%
Exceeding 200 AMP Service	$20.97		$21.10		$0.13	0.62%
Energy Charge - All Kilowatt Hours (Cents/kWh)						
Winter Seasonal	$0.13156		$0.13251		$0.00095	0.72%
Non-Winter Seasonal	$0.10906		$0.11001		$0.00095	0.87%
Minimum Monthly Charge						
Not Exceeding 200 AMP service	$15.97		$16.10		$0.13	0.81%
Exceeding 200 AMP Service	$20.97		$21.10		$0.13	0.62%
Prompt Payment Discount	1.50%		1.50%		-	-
G.S. 0-100 kW (110 kVA) - RATE # 2.1						
Total Customers for Class (000's)	22,796		22,977		181	0.79%
Basic Customer Charge (Monthly)						
Umetered	$12.13		$12.30		$0.17	1.40%
Single Phase	$20.13		$20.30		$0.17	0.84%
Three Phase	$32.13		$32.30		$0.17	0.53%
Demand Charge Regular						
Winter (kW)	$9.79		$9.85		$0.06	0.61%
Other (kW)	$7.29		$7.35		$0.06	0.82%
Energy Charge - All Kilowatt Hours (Cents/kWh)						
First 3,500 kilowatt-hours	$0.12062		$0.12155		$0.00093	0.77%
All excess kilowatt-hours	$0.09074		$0.09145		$0.00071	0.78%
Maximum Monthly Charge	$0.20934	plus B.C.C.	$0.21096	plus B.C.C.	$0.00162	0.77%
Minimum Monthly Charge						
Umetered	$12.13		$12.30		$0.17	1.40%
Single Phase	$20.13		$20.30		$0.17	0.84%
Three Phase	$32.13		$32.30		$0.17	0.53%
Prompt Payment Discount	1.50%		1.50%		-	-

Table 50: Existing and Proposed Rates, Tolls & Charges (Cont`d)

	EXISTING RATES October 1, 2019		PROPOSED RATES March 1, 2022		CHANGE ($)	CHANGE (%)
G.S. 110-1000 kVA - RATE # 2.3						
Total Customers for Class (000's)	1,267		1,269		2	0.16%
Basic Customer Charge (Monthly)	$49.38		$49.76		$0.38	0.77%
Demand Charge						
Winter (kVA)	$8.21		$8.27		$0.06	0.73%
Other (kVA)	$5.71		$5.77		$0.06	1.05%
Energy Charge (Cents/kWh)						
First 150 kWh per kVA of demand (max 50,000)	$0.10270		$0.10349		$0.00079	0.77%
All Excess kWh	$0.08292		$0.08356		$0.00064	0.77%
Maximum Monthly Charge (Cents/kWh + BCC)	$0.20934	plus B.C.C.	$0.21096	plus B.C.C.	$0.00162	0.77%
Minimum Monthly Charge	$49.38		$49.76		$0.38	0.77%
Prompt Payment Discount	1.50%		1.50%		-	-
G.S. 1000 kVA and Over - RATE # 2.4						
Total Customers for Class (000's)	57		57		-	-
Basic Customer Charge (Monthly)	$86.05		$86.71		$0.66	0.77%
Demand Charge						
Winter (kVA)	$7.88		$7.92		$0.04	0.51%
Other (kVA)	$5.38		$5.42		$0.04	0.74%
Energy Charge (Cents/kWh)						
First 75,000 kWh	$0.09905		$0.09981		$0.00076	0.77%
All Excess kWh	$0.08211		$0.08275		$0.00064	0.78%
Maximum Monthly Charge (Cents/kWh + BCC)	$0.20934	plus BCC	$0.21096	plus BCC	$0.00162	0.77%
Minimum Monthly Charge	$86.05		$86.71		$0.66	0.77%
Prompt Payment Discount	1.50%		1.50%		-	-
STREET & AREA LIGHTING RATES						
Total Customers for Class (000's)	10,793		10,862		69	0.64%
FIXTURES						
Sentinel/Standard						
High Pressure Sodium						
100W	$17.89		$18.05		$0.16	0.89%
150W	$22.02		$22.44		$0.42	1.91%
250W	$30.55		$31.84		$1.29	4.22%
400W	$41.87		$44.65		$2.78	6.64%
Light Emitting Diode						
LED 100	$16.20		$16.18		-$0.02	-0.12%
LED 150	$17.70		$18.16		$0.46	2.60%
LED 250	$22.68		$21.97		-$0.71	-3.13%
LED 400	$25.71		$25.29		-$0.42	-1.63%
Post Top						
High Pressure Sodium						
100W	$19.30		$19.28		-$0.02	-0.10%
Poles						
Wood	$6.27		$6.49		$0.22	3.51%
30' Concrete or Metal, direct buried	$8.95		$9.06		$0.11	1.23%
45' Concrete or Metal, direct buried	$14.65		$15.04		$0.39	2.66%
25' Concrete or Metal,Post Top, direct buried	$6.67		$6.41		-$0.26	-3.90%
Underground Wiring						
All sizes and types of fixtures	$15.28		$15.28		-	-

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 March 1, 2022 and the factors proposed in this Application.

Newfoundland Power Inc. **Schedule 1**

Comparison of Total Cost of Energy to kWh Sold

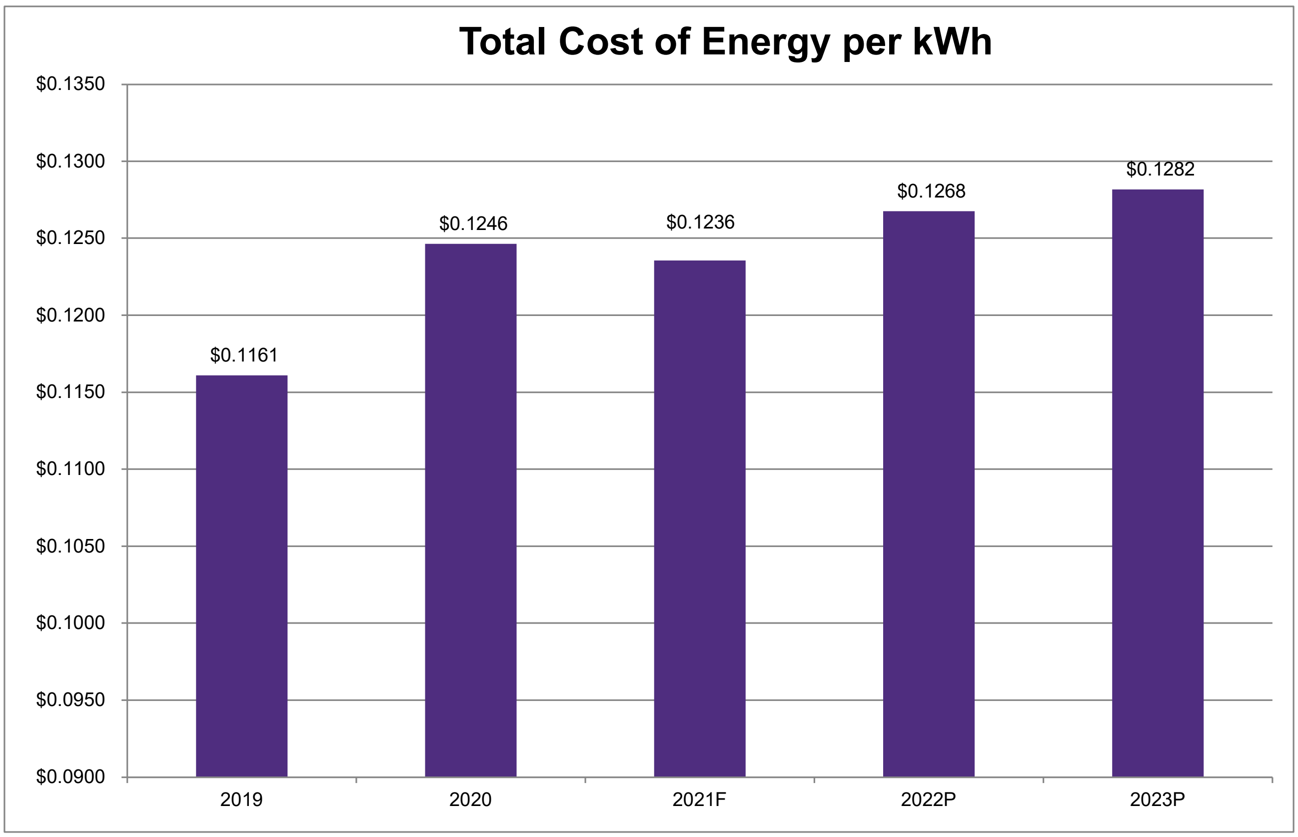
(000)'s

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation / Deferrals	Finance Charges	Income Taxes	Net Income	Total Cost of Energy	Cost per kWh
2019	5,846,600	$ 71,280	$ 444,861	$ 63,818	$ 35,061	$ 18,324	$ 45,395	$ 678,739	$ 0.1161
2020	5,729,000	$ 78,591	$ 468,844	$ 64,106	$ 36,719	$ 19,338	$ 46,469	$ 714,067	$ 0.1246
2021F	5,719,500	$ 79,988	$ 464,060	$ 66,863	$ 34,711	$ 17,698	$ 43,333	$ 706,653	$ 0.1236
2022P	5,699,300	$ 76,240	$ 464,811	$ 70,064	$ 34,712	$ 22,154	$ 54,479	$ 722,460	$ 0.1268
2023P	5,661,600	$ 75,997	$ 459,924	$ 75,696	$ 33,074	$ 24,198	$ 56,788	$ 725,677	$ 0.1282

(1) 2019 to 2021 is based on information provided in Exhibit 3 of the supporting materials to the GRA.

(2) 2022 to 2023 is based on information provided in Exhibit 5 of the Supporting Materials to the GRA.

(3) Figures presented excludes non-regulated activity.



Newfoundland Power Inc. **Schedule 2**

Comparison of Gross Operating Expenses to kWh Sold

(000's)

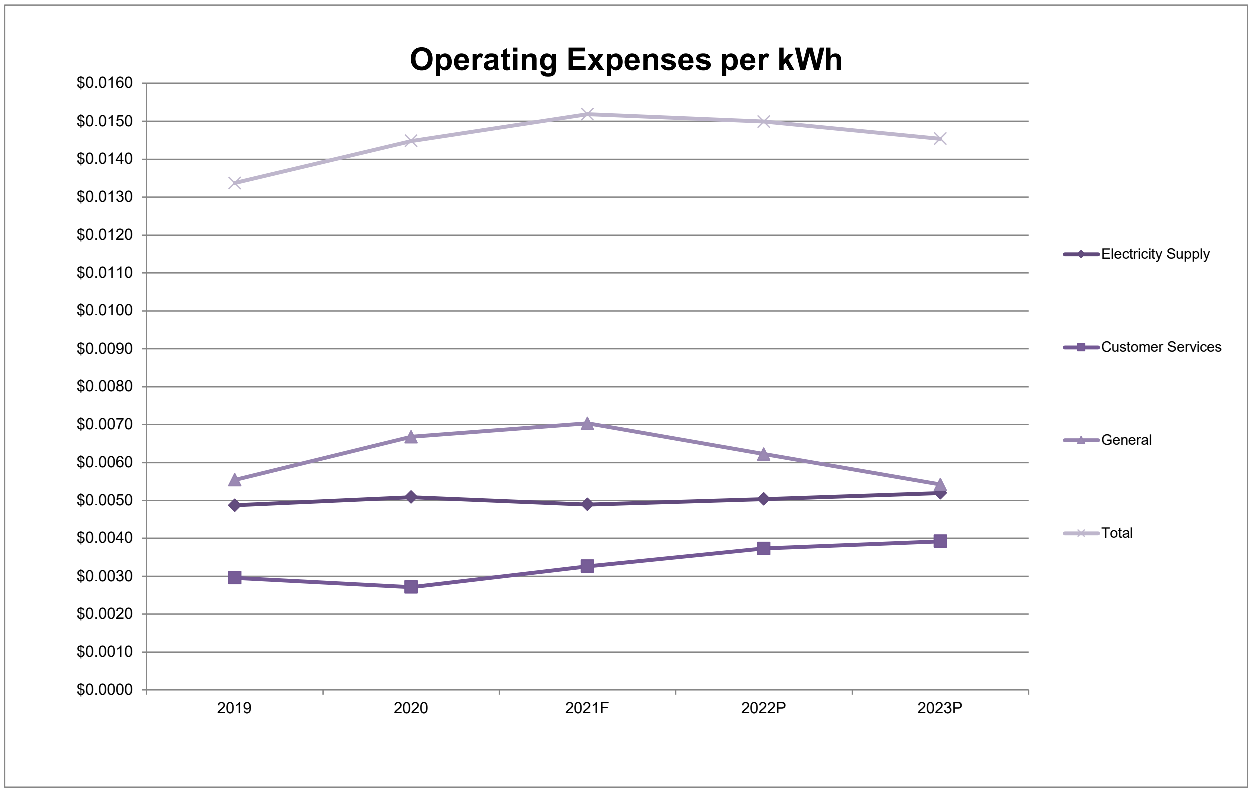
		Electricity Supply		Customer Services[2]		General[3]		Totals	
Year	kWh sold	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh
2019	5,846,600	$ 28,473	$0.0049	$ 17,298	$0.0030	$ 32,394	$0.0055	$ 78,165	$0.0134
2020	5,729,000	$ 29,144	$0.0051	$ 15,555	$0.0027	$ 38,254	$0.0067	$ 82,953	$0.0145
2021F	5,719,500	$ 27,972	$0.0049	$ 18,658	$0.0033	$ 40,223	$0.0070	$ 86,853	$0.0152
2022P	5,699,300	$ 28,705	$0.0050	$ 21,280	$0.0037	$ 35,452	$0.0062	$ 85,437	$0.0150
2023P	5,661,600	$ 29,422	$0.0052	$ 22,207	$0.0039	$ 30,691	$0.0054	$ 82,320	$0.0145

(1) Based on information in Exhibit 1 of the supporting materials to the GRA.

(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.



About Grant Thornton in Canada
Grant Thornton LLP is a leading Canadian accounting and advisory firm providing audit, tax and advisory services to private and public organizations. We help dynamic organizations unlock their potential for growth by providing meaningful, actionable advice through a broad range of services. Grant Thornton LLP is a Canadian member of Grant Thornton International Ltd, whose member and correspondent firms operate in over 100 countries worldwide. A listing of Grant Thornton offices and contact information can be found at: www.GrantThornton.ca

grantthornton.ca