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MARITIME ELECTRIC
A FORTIS COMPANY

November 8, 2022

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The Island Regulatory
and Appeals Commission

Ms. Cheryl Mosher
Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Mosher:

General Rate Application - Docket UE20946
Response to Interrogatories from Commission Staff

Please find attached the Company's response to Interrogatories ("IRs") from Commission Staff with respect to the General Rate Application filed on June 20, 2022.

As you know, the Company has applied to the Commission to have certain interrogatory responses remain confidential. The Company is deferring our response to IRs 12, 15, 16, 18, 40 and 41 until the Commission reaches a decision on this Application.

An electronic copy of this submission will be forwarded shortly.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett, CPA, CA
Manager, Regulatory & Financial Planning

GCC33
Enclosure

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

General Rate Application
Docket UE20946

Submitted November 8, 2022

IR-1 On page 8 of the General Rate Application (the "Application"), lines 5 to 7, Maritime Electric states:

Second, the Net Zero Report plans to evaluate and invest in ways to convert various types of waste into clean energy that can be then used to heat homes and power vehicles. Maritime Electric will be required to play a role in distributing this energy source to its customers.

a) Why is Maritime Electric "*required*" to play a role in distributing energy from waste to its customers?
b) Please explain what Maritime Electric's role would be in distributing energy from waste.
c) Would this require any operating or capital expenditures? If yes, please provide specifics including forecast operating and capital costs.
d) Will Maritime Electric be required to purchase energy from waste? If yes, what is the unit cost of energy from waste, and how does the unit cost compare to other energy sources purchased by Maritime Electric?

Response:

a. On pages 7 and 8 of the Application, Maritime Electric discusses the Provincial Government's 2040 Net Zero Framework ("Net Zero Report"). The Net Zero Report includes plans to "evaluate and invest in ways to convert various forms of waste into clean energy that can be then used to heat homes and power vehicles".[1] Given Maritime Electric's role as the primary distributor of electricity on Prince Edward Island, the Company has inferred that it will be "required" to facilitate the distribution of any electricity generated from waste, should the Government's plan ultimately be executed.

b. Maritime Electric's precise role in distributing energy from waste is yet to be determined, and will depend on the outcome of the Government's plan to convert various types of waste into clean energy.

c. See response to IR-1(b).

d. See response to IR-1(b).

[1] 2040 Net Zero Framework: Accelerating Our Transition to a Clean, Sustainable Economy, pages 35 to 38.

IR-2 On page 8 of the Application, lines 17 to 18, Maritime Electric further states that "*analyses and actions must begin now to ensure the Net Zero Report goals and objectives can be achieved*."

Maritime Electric continues to state (page 8, lines 20 to 24) that the Net Zero Report will influence Maritime Electric's long-term planning of the electrical system, and that the Integrated System Plan will address the investment required to accommodate the increased demand for electricity.

a) What, if any, obligation does MECL have to achieve the goals and objectives of the Net Zero Report?
b) What impact will the Net Zero Report goals and objectives have on Maritime Electric's Integrated System Plan and anticipated capital expenditures?
c) What are the forecast costs (operating and capital) of achieving the Net Zero Report goals and objectives?
d) Who will pay for the forecast operating and capital costs?

Response:

a. Currently, Maritime Electric has no explicit obligation to achieve the goals and objectives of the Net Zero Report. However, as the primary distributor of electricity on Prince Edward Island ("PEI"), it is reasonable to assume that the Provincial Government's generation of electricity will ultimately require Maritime Electric's participation in the distribution of that electricity.

b. It is unknown what impact, if any, the Net Zero Report goals and objectives will have on Maritime Electric's Integrated System Plan and anticipated capital expenditures. Likewise, there are currently no forecast operating or capital costs to be incurred by Maritime Electric. Any impact on Maritime Electric will be contingent on whether the goals and objectives outlined in the Net Zero Report are ultimately achieved.

c. See response to IR-2(b).

d. See response to IR-2(b).

IR-3 On pages 11 and 12 of the Application, Maritime Electric states that it is not proposing any change to the monthly service charge for applicable customer classes. However, Maritime Electric has removed the Residential Rural rate (Rate Code 130) from the Schedule of Rates in Appendix A to the Application.

a) Please explain. Is Maritime Electric proposing a single monthly service charge for all Residential customers (rural and urban)?

b) Please explain why Maritime Electric is not proposing any change to the demand charge or the monthly service charge for applicable customers. When were the demand charge and monthly service charge last changed?

Response:

a. No, there is no proposal for a single monthly service charge in the Application. The rows for the residential rural rate class were inadvertently hidden in Appendix N-28 as originally filed. Please see attached IR-3 - Attachment 1 - Amended N-28 which includes the Residential Rural rate class. In addition, please refer to Table 7-4 and 7-5, on pages 101 and 102 of the Application, which clearly distinguish separate rural and residential rate classes.

b. Maritime Electric has not proposed any changes to the demand or service charges for any of the customer rate classes as it believes this issue is better addressed in stage 2 of the Rate Design Application, Docket UE22503.

In preparing the General Rate Application, the Company did consider whether changes to the demand and/or service charges should be part of this proceeding. The analysis conducted suggested that the current demand and service charges are not unreasonable, with only refinements recommended. However, directionally, those refinements are counter to the plans to align the revenue-to-cost ratios within the approved target range. This indicates that further analysis is required to ensure all rate elements, both the rate design and the rate itself, work together to achieve the desired results. Therefore, the Company choose to address the demand and service charges as part of stage 2 of the Rate Design Application.

The monthly service charges and demand charges were last changed effective April 1, 2009, as shown in the following table.

TABLE 1
Maritime Electric Service Charges and Demand Charges

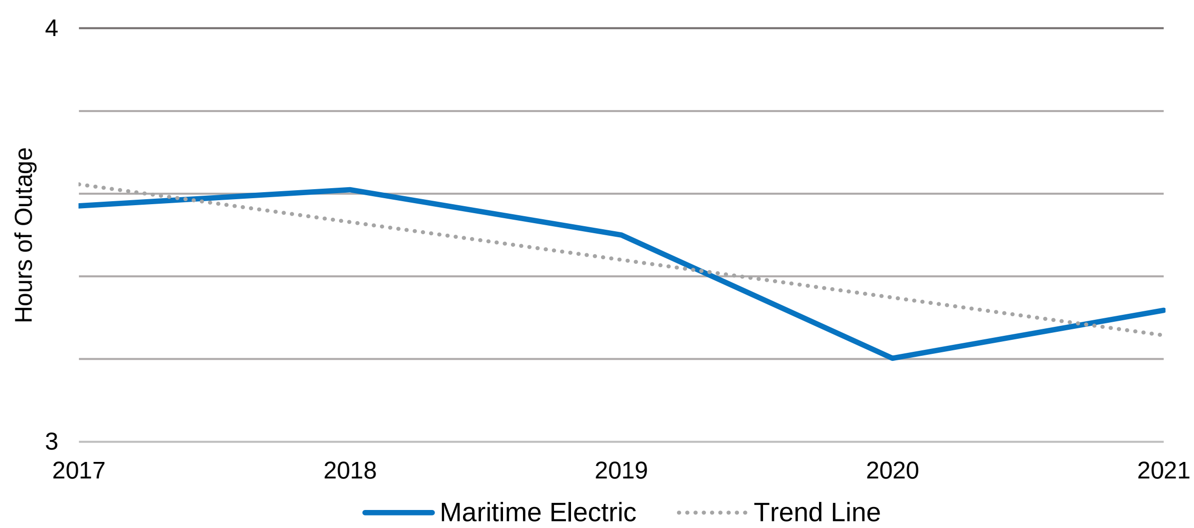
Rate Code	Rate Description	Effective April 1, 2008	Effective April 1, 2009
110	Residential Urban service charge	22.67	24.57
130	Residential Rural service charge	24.83	26.92
232	General Service 1 service charge	22.67	24.57
232	General Service 1 demand charge	12.39	13.43
320	Small Industrial demand charge	6.88	7.46
310	Large Industrial demand charge	13.38	14.50

IR-4 On page 20 of the Application, lines 10 to 12, Maritime Electric states that customer outages under normal operating conditions have improved since 2012. However, according to Chart 4-4 (page 20 of the Application), it appears that SAIDI under normal operating conditions has remained fairly constant. Please explain how SAIDI has improved since 2012.

Response:

To identify reliability trends over time, Maritime Electric calculates the five-year rolling average for the reliability metric being analyzed. As shown in Figure 1, the Company's five-year rolling average for SAIDI (MED Excluded) is trending downwards.

Figure 1
Maritime Electric SAIDI (MED Excluded)
Five-Year Rolling Average
2017 to 2021



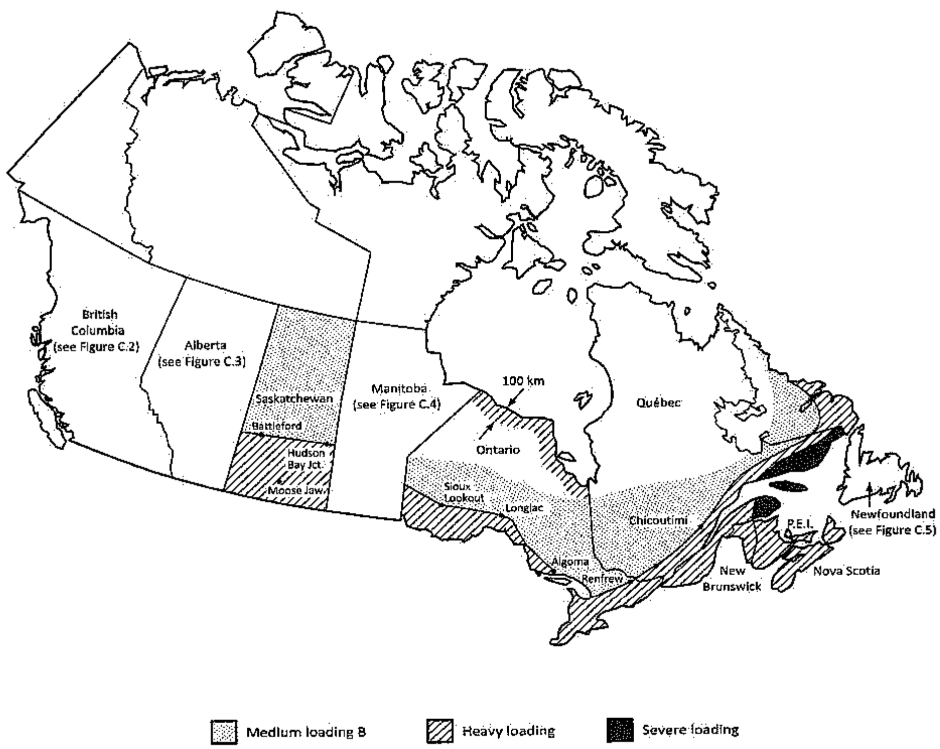
This downward trend reflects the Company's diligence in monitoring reliability performance and responding with the appropriate balance of operating controls and capital investments. Operating controls are applied to improve reliability through system maintenance, outage avoidance (e.g., live-line work methods) and outage response (i.e., prompt and strategic to identify and isolate problems quickly). Capital investments help to ensure that aged, deteriorated or overloaded electrical system components are replaced in a timely manner and provide for other system improvements that benefit customers over the life cycle of these investments.

IR-5 According to Chart 4-4 (page 20 of the Application), SAIDI under normal operating conditions (MED Excluded), it appears as though Maritime Electric's infrastructure is on par or performing better than Electricity Canada and Atlantic utilities. However, based on Chart 4-5 SAIDI (All In) (page 22 of the Application), Maritime Electric's outages are trending higher than both Electricity Canada and Atlantic utilities. Please explain why major storms or events appear to have a more negative affect on Maritime Electric's grid.

Response:

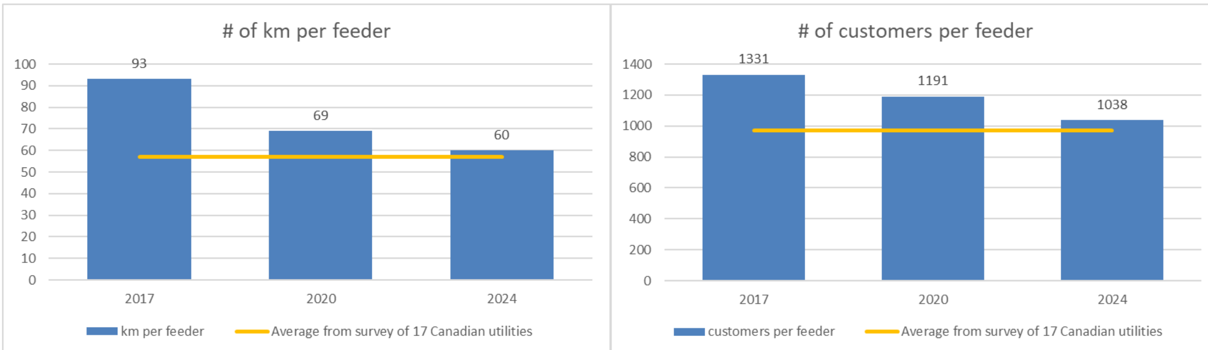
Canadian Standards Association ("CSA") C22.3 No. 1:20 Overhead Systems, which provides requirements for the construction of overhead electrical systems, classifies the weather load conditions on PEI as "heavy" (see Figure 1). This indicates that Maritime Electric's service territory is susceptible to more significant ice and wind loads relative to some of the Electricity Canada member utilities included in the average shown in Chart 4-5. Such exposure to extreme weather events was experienced on PEI in 2018 and 2019, which had a significant negative effect on Maritime Electric's SAIDI (All In) reliability performance.

Figure 1
Electricity Canada Weather Load Conditions Map



Another factor affecting Maritime Electric's past SAIDI (All In) reliability performance, is that the Company's distribution feeders are longer and serve more customers than the average of 17 Canadian utilities that responded to a Maritime Electricity survey in 2017, as shown in Figure 2. Consequently, based on the average line length and customer count of these other Canadian utilities, Maritime Electric feeder outages tend to impact more customers when they occur.

Figure 2
Maritime Electric Feeder Length and Customer Count Comparison
2017 to 2024



As load continues to grow, Maritime Electric is adding substations which reduces its average feeder length and customer count per feeder. With the completion of the Tignish substation project in 2024, as proposed in the 2023 Capital Budget Application, the Company's average feeder length and customer count relative to 2017, will be improved by 35 and 22 per cent, respectively.

Other factors likely contributing to Maritime Electric's SAIDI (All In) being higher than other Electricity Canada and Atlantic utilities include the radial nature of Maritime Electric's electrical system. A radial electrical system has a single path over which current may flow. This limits the Company's ability to restore power quickly through switching to feeds from alternate sources when outages occur. Also, Maritime Electric's relatively small geographic service territory is susceptible to Island-wide storm impacts, which limits the ability to redirect resources from non-impacted areas to help with restoration, as is often possible for utilities with larger service territories and more-often localized storm impacts. Maritime Electric has recently invested in additional system redundancy with major projects such as Y-104 and the Lorne Valley switching station, and is planning to continue improving redundancy with the Woodstock switching station project, as proposed in the 2023 Capital Budget Application.

IR-6 On page 29 of the Application, lines 24 to 28, Maritime Electric states that its methodology in developing the sales forecast for the rate-setting period is consistent with that used in recent filings and with the sales forecast reviewed by Grant Thornton in 2020.

a) Please provide an explanation of the sales forecast methodology.
b) Please explain any changes in the methodology since it was reviewed by Grant Thornton in 2020.
c) Please provide an explanation of any material change in the inputs or assumptions since the methodology was reviewed by Grant Thornton in 2020.

Response:

a. Maritime Electric's sales forecast model consists of five components:

- Residential space heating;
- Residential non-space heating;
- Commercial, which includes the General Service, Small Industrial and Unmetered rate classes;
- Large Industrial; and
- Street Lighting.

Residential Space Heating

Forecasting the Residential space heating load, which cannot be metered separately, begins with an analysis of the historical load. A regression analysis of monthly megawatt hour ("MWh") sales and monthly heating degree days ("HDD") is used to estimate historical space heating loads. PEI's heating season runs from October through to May, so these eight months are used to obtain an average historical coefficient value, which is expressed in terms of MWh per HDD. The space heating load for a year is, therefore, the MWh per HDD coefficient times the annual HDD.

The space heating load forecast is also based on the estimated population growth on PEI, which is provided by the Conference Board of Canada ("CBOC"). Using a historical relationship based on regression analysis, the annual increases in population are converted to annual housing starts.[2] The annual forecast increase in the heating load coefficient due to housing starts is added to the historical heating load coefficient to give a forecast heating load coefficient for each year of the forecast period. Table 1 shows the calculation of the forecast increase in the space heating load coefficient for 2023.

[2] The CBOC housing starts is translated into housing types consisting of single detached, semi-detached and multi-unit. Maritime Electric's service territory also consists of mobile homes and cottages, whose forecast housing starts are based on the Company's historical information. In addition, the Company forecasts, based on historical information, the number of 200 amp service upgrades. Finally, the forecast number of mini-split retrofits was based on information provided by the PEI Energy Corporation a few years ago.

Table 1 Forecast of Growth in Residential Space Heating for 2023					
	Estimated Housing Starts (#) A	Portion in MECL Service Territory[3] (%) B	Portion with Electric Heat[4] (%) C	Space Heating Usage	
				Annual Average (kWh) D	Annual Increase (MWh) E[5]
Single detached	458	95	80	8,500	2,959
Semi detached	172	90	95	7,400	1,088
Multi-unit	515	90	90	3,400	1,418
Mobile homes	80	100	90	6,400	461
Cottages	100	100	50	2,900	145
200 amp service upgrades	190	100	50	6,500	618
Mini-split retrofits	1,733	100	100	4,700	8,145
Total					**14,834**
14,834 MWh / 2,780 HDD = 5.3 MWh per HDD					

As Table 1 illustrates, the forecast annual increase in space heating usage, of 14,834 MWh, is divided by the 10-year HDD average, of 2,780 HDD, to calculate the space heating load coefficient, of 5.3 MWh per HDD.

The resulting 5.3 MWh per HDD is added to an historical heating load coefficient of 76.0 MWh per HDD, which was derived from another regression analysis, to calculate the forecast heating load coefficient of 81.3 MWh per HDD for October 2022 to September 2023, which is increased again by 5.3 MWh per HDD to get the coefficient for the next period, October 2023 to September 2024. Table 2 below illustrates how this information is used to forecast the space heating load for 2023.

TABLE 2 2023 Forecast of Space Heating Load				
Heading Load Coefficient A		Annual HDD B	Prorated C	2023 Forecast Space Heating Load[6] (kWh) D = AxBxC/1,000
January – September 2023	81.3	2,780	9/12	169.6
October – December 2023	86.0	2,780	3/12	60.1
				229.8

3 95 per cent reflects Maritime Electric's 90 per cent share of the total electricity provided on PEI increased to 95 per cent to account for the limited ability for single detached housing to be constructed in the City of Summerside; 90 per cent reflects Maritime Electric's share of the total electricity provided on PEI; and 100 per cent reflects that the forecast is based on the Company's historical information.

4 Each percentage is based on Maritime Electric's historical information.

5 E = A x B x C x D / 1000

6 Calculations reflect rounding of more precise calculations from the Excel forecast model.

The forecast heating load coefficient for 2023 is 81.3 MWh/HDD and the forecast space heating load is 229.8 GWh.

Residential Non-space Heating Load

There are four inputs to the Residential non-space heating load component of the forecast:

- CBOC forecast of population growth for PEI;
- Demand Side Management ("DSM") programs by efficiencyPEI;
- Growth in electric vehicle ("EV") charging load; and
- Growth in rooftop solar installations.

The historical non-space heating loads are equal to the total Residential load minus the estimated space heating loads, as described below.

Similar to the forecast of space heating loads, the forecast for non-space heating load begins with the CBOC population growth forecast translated into housing starts. The annual increases in non-space heating load due to housing starts are added to the historical load to give a forecast non-space heating load for each year of the forecast period.

One of the objectives of efficiencyPEI's DSM programs is to reduce electricity usage on PEI. The Residential sales forecast reflects this by reducing the above estimated non-space heating load by the expected savings in electricity usage due to the residential component of efficiencyPEI's programs. The estimated cumulative reduction in Residential energy sales in 2023 is 19.3 GWh.[7]

The estimated impact of EV charging on Residential sales begins with a forecast increase in the number of EVs, which is based on the forecast of EV charging load for New Brunswick prorated for PEI based on population.[8] The average energy consumption of each EV is estimated based on converting the average annual gasoline usage by PEI vehicles to kWh sales.[9] This results in the estimation that EV charging will increase energy sales by 3.6 GWh in 2023.[10]

Residential sales will decrease due to the continued installations of rooftop solar. The average number of residential rooftop solar installations in 2023 is estimated to be 1,639, which will generate an estimated 14.1 GWh.[11] Maritime Electric's analysis has shown that, on average, one third of the electricity generated by residential rooftop solar is used directly behind the meter to supply household loads, which reduces the amount of electricity sold by the Company. The remaining two thirds is supplied to the grid and is measured by a reverse flow meter. Therefore, it is estimated that energy sales will decrease by 4.7 GWh in 2023.[12]

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7 This cumulative number was derived from an analysis beginning in 2019, when the efficiencyPEI's DSM program began.

8 The number of EVs on PEI is forecast to increase by 400 in 2023 to a total of 1,200.

9 Average annual gasoline usage on PEI is 1,500 litres. Using a conversion factor of 2 kWh in an EV battery equaling 1 litre of gasoline, an EV on PEI is estimated to use 3,000 kWh annually.

10 1,200 EVs x 3,000 kWh per year / 1,000,000 = 3.6 GWh per year

11 The estimated electricity generated by rooftop solar installations is based on available information on the size of the installations along with a Natural Resource Canada's solar capacity factor adjusted for PEI.

12 14.1 GWh / 3 = 4.7 GWh

Commercial
The Commercial component of the sales forecast model includes General Service, Small Industrial and Unmetered rate classes. A regression analysis of historical annual sales as a function of historical PEI real annual Gross Domestic Product ("GDP") is applied to the CBOC forecast of GDP to estimate sales growth.

Similar to the Residential sales forecast, the objectives of efficiencyPEI's DSM programs is expected to reduce Commercial sales. The estimated cumulative reduction in Commercial sales in 2023 largely offsets forecast sales growth.

Large Industrial
The Large Industrial load has remained essentially constant in recent years, as it is dominated by one customer with a stable load. Forecast changes in Large Industrial sales would be based on known customer expansion plans and trending of individual customer historical usage.

Street Lighting
Energy sales for this rate class were increasing at approximately 1 per cent annually until 2014. Energy sales have declined steadily due to Maritime Electric's 10-year LED conversion program, which began in 2015. Street lighting sales are expected to resume to 1 per cent annual growth, reflecting an increase in the number of street lights, following the completion of the LED conversion program.

Table 3 shows the cumulative impact of each element of the 2023 sales forecast. The same exercise was completed to forecast sales for 2024 and 2025.

TABLE 3 2023 Sales Forecast (GWh)	
1. Residential space heating load	229.8
2. Residential non-space heating load before:	514.1
Cumulative reduction due to DSM	(19.3)
Residential EV charging load	3.6
Reduction due to rooftop solar	(4.7)
3. Commercial load before DSM	523.3
Cumulative reduction due to DSM	(22.4)
4. Large Industrial	163.5
5. Street lighting	3.8
Total	**1,391.7**

b. The following three changes have been made to the forecast methodology since it was reviewed by Grant Thornton in 2020:

- Contribution to Residential sales from EV charging load;[13]
- Reduction in Residential sales due to rooftop solar installations;[14] and
- Real price of electricity is no longer used as an input variable in the Commercial forecast model due to low statistical significance.[15]

The first two changes were made to the forecast methodology because the impacts of EV charging load and rooftop solar installations on sales is now large enough to warrant inclusion. The third change did not have a material impact on the results of the forecast methodology.

c. In addition to the changes described in the response to IR-6 (b), there has been a change in the assumptions about Residential space heating load for 2022. This is discussed in the responses to IR-8 (a) and IR-8 (e).

[13] As described in part (a) of this response.
[14] As described in part (a) of this response.
[15] The "real price of electricity" refers to the determination of how the actual price of electricity has changed compared to changes in the annual consumer price index ("CPI"). Historically, Maritime Electric's price of electricity has increased by a rate greater than CPI and this was factored into the regression analysis. In the forecast provided in the Application, it was determined that the price of electricity in recent years was increasing by a rate comparable to CPI and, therefore, the "real price of electricity" did not need to be factored into the current regression analysis.

IR-7 Table 4-3 (page 30) of the Application provides the 2023 forecast number of customers, energy sales and total revenue by customer class. Please provide the same table and information for 2024 and 2025.

Response:

Table 1 provides the 2024 and 2025 forecast number of customers, energy sales and total revenue by customer class as was provided for 2023 in Table 4-3 of the Application.

TABLE 1
2023 and 2024 Forecast Customer Base

Customer Category	% of Total Customers		% of Total Energy Sales		% of Total Revenue	
	2024	2025	2024	2025	2024	2025
Residential	84.4	84.4	52.5	53.3	56.5	57.2
General Service	11.0	11.0	28.2	27.7	29.4	28.9
Large Industrial	0.0	0.0	11.9	11.7	6.9	6.8
Small Industrial	0.3	0.3	6.9	6.8	6.1	6.0
Street Lighting/Unmetered	4.3	4.3	0.5	0.5	1.1	1.1
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

IR-8 According to Table 4-4 (page 31 of the Application), Maritime Electric is forecasting a 29.7 percent increase in the Residential space heating load in 2022, and annual increases of 3.1 to 6.3 percent during the rate-setting period.

a) Please explain how Maritime Electric forecast the 2022 Residential space heating load, including all inputs and assumptions.
b) Please provide Maritime Electric's load forecast for the rate-setting period, together with an explanation of the forecast methodology, including all inputs and assumptions.
c) Please explain any changes in the methodology since it was reviewed by Grant Thornton in 2020.
d) Please provide an explanation of any material change in the inputs or assumptions since the methodology was reviewed by Grant Thornton in 2020.
e) Specifically, please explain Maritime Electric's assumption that the Residential space heating load will remain at 2022 forecast and continue to grow.

Response:

a. The 2022 energy sales forecast reflects actual sales for January to March and forecast sales for April to December. Maritime Electric's analysis suggested that the sales for January to March were the result of electricity prices being temporarily lower than furnace oil prices. Therefore, the Company did not believe it was appropriate to assume that level of sales growth would continue.

The following describes the process for forecasting sales for April to December 2022.

Actual sales for January to March were 42.6 GWh, or 11.3 per cent, higher than the same period in 2021, which was much higher than the preceding forecast increase of 3.7 per cent for all of 2022. Before submitting the Application in June 2022, the Company analyzed this unexpected increase. Table 1 shows the forecast annual variance between 2021 actual sales and 2022 forecast sales compared to the actual variance between March 2021 year-to-date ("YTD") sales and March 2022 YTD sales.

TABLE 1 Sales Analysis						
	Annual Sales			**Year-to-Date Sales**		
(GWh)	**2021 Actuals**	**2022 Forecast**	**Variance**	**March 2021 Actuals**	**March 2022 Actuals**	**Variance**
Residential – space heating[16]	171.8	215.0	43.2	93.8	113.7	19.8
Residential – non-space heating[16]	518.6	490.5	(28.1)	125.7	139.8	14.2
Residential Subtotal	**690.4**	**705.5**	**15.1**	**219.5**	**253.5**	**34.0**
Commercial[17]	477.5	501.7	24.2	121.8	126.4	4.6
Large Industrial	153.8	163.5	9.7	34.3	38.4	4.1
Street Lighting	4.3	3.8	(0.5)	1.1	1.0	(0.1)
Total	**1,326.0**	**1,374.5**	**48.5**	**376.7**	**419.3**	**42.6**
Variance %			***3.7%***			***11.6%***

Table 1 illustrates that Residential non-space heating load was forecast to decrease in 2022 compared to 2021, which was based on the assumption that pandemic-related restrictions would be lifted and people would be returning to work and school.[18]

The next step was to analyze the split between space heating and non-space heating load for YTD March 2022. Table 2 demonstrates how the space heating component was estimated, with non-space heating load accounting for the remaining sales. Using the same inputs as was used in developing the 2022 forecast per Table 1, the YTD March 2022 Residential sales increased by 19.8 GWh due to space heating load, resulting in an increase of 14.2 GWh due to non-space heating load. When compared to the expectation that non-space heating load would decrease in 2022, an increase of 14.2 GWh did not seem reasonable.

16 For actual columns, the subtotal of Residential sales is known but the split between space heating and non-space heating is an estimated.
17 Commercial includes General Service, Small Industrial and Unmetered rate classes.
18 Actual sales for 2020 and 2021, during pandemic restrictions, showed a shift between Residential and General Service sales, suggesting that during business and school closures electricity normally consumed under the General Service rate class was being consumed under the Residential rate class.

TABLE 2[19] Original Estimate of Residential Heating Load							
	Residential Heading Load Coefficient		HDD below 12 C			Estimated Residential Space Heating Load	
Month	2021 (MWh/HDD)	2022 (MWh/HDD)	10 Year Average	2021	2022	2021 (GWh)	2022 (GWh)
Dec previous year			443	340	419		
Jan	70.3	76.0	561	473	593	28.6	38.4
Feb	70.3	76.0	524	485	489	33.7	41.1
Mar	70.3	76.0	465	413	411	31.6	34.2
March YTD Subtotal						**93.9**	**113.7**
Apr	70.3	76.0	268	226	268	22.5	25.8
May	70.3	76.0	111	124	111	12.3	14.4
Jun	70.3	76.0	20	8	20	4.6	5.0
Jul	70.3	76.0	0	-	0	0.3	0.8
Aug	70.3	76.0	0	-	0	-	0.0
Sep	70.3	76.0	14	3	14	0.1	0.5
Oct	76.0	81.3	102	68	102	2.7	4.7
Nov	76.0	81.3	266	224	266	11.1	15.0
Dec	76.0	81.3	443	419	443	24.4	28.8
Total			**2,773**	**2,443**	**2,717**	**171.8**	**208.7**
						Annual Increase	**36.9**
						March YTD Increase	**19.8**

The next step was to determine if the heating load coefficient of 76.0 MWh per HDD for October 2021 to September 2022 was still valid.[20] A regression analysis was completed on the monthly Residential load against monthly HDD for October 2021 to March 2022, which resulted in an updated heating load coefficient of 84.8 MWh per HDD. The Company believes the higher coefficient was due to customers resorting to short-term measures, such as plug-in electric heaters, to reduce furnace oil usage in response to high furnace oil prices in early 2022.

The next step was to use the updated heating load coefficient to estimate Residential heating load for the remainder of 2022, as shown in Table 3.

19 The Excel version of this table is provided in IR-8 Attachment 1.
20 The forecast heating load coefficient of 76.0 was based on heating load growth due to housing starts, and was a key variable in the preceding sales forecast.

TABLE 3[21] Revised Estimate of Residential Heating Load							
	Residential Heading Load Coefficient		Heating Degree Days 12 C			Estimated Residential Space Heating Load	
Month	2021 (MWh/HDD)	2022 (MWh/HDD)	10 Year Average	2021	2022	2021 (GWh)	2022 (GWh)
Dec previous year			443	340	419		
Jan	70.3	84.8	561	473	593	28.6	42.9
Feb	70.3	84.8	524	485	489	33.7	45.9
Mar	70.3	84.8	465	413	411	31.6	38.2
March YTD Subtotal						**93.9**	**127.0**
Apr	70.3	84.8	268	226	268	22.5	28.8
May	70.3	84.8	111	124	111	12.3	16.1
Jun	70.3	84.8	20	8	20	4.6	5.6
Jul	70.3	84.8	0	-	0	0.3	0.9
Aug	70.3	84.8	0	-	0	-	0.0
Sep	70.3	84.8	14	3	14	0.1	0.6
Oct	84.8	81.3	102	68	102	3.0	4.7
Nov	84.8	81.3	266	224	266	12.4	15.0
Dec	84.8	81.3	443	419	443	27.3	28.8
Total			**2,773**	**2,443**	**2,717**	**176.2**	**227.3**
						Annual Increase	**51.0**
						YTD March Increase	**33.1**

Table 3 estimates that, with an updated heating load coefficient, the YTD March 2022 Residential sales increased 33.1 GWh due to space heating load with the remaining increase of 0.9 GWh due to non-space heating load. This result was more reasonable based on what was forecast for 2022.

The next step was to use the updated annual increase in Residential space heating load of 51.0 GWh, per Table 3, to update the 2022 Residential sales forecast.

In the November 2021 forecast, Residential non-space heating load was expected to decrease by 28.1 GWh in 2022 due to the easing of pandemic related restrictions. However, restrictions were re-imposed in December 2021 and the reduction in Residential non-space heating load was adjusted to 14.1 GWh as shown in Table 4.

21 The Excel version of this table is provided in IR-8 - Attachment 1.

TABLE 4 2022 Sales - Revised Estimate						
	YTD Actual Sales			Updated 2022 Forecast		
(GWh)	March 2021	March 2022	Variance	2021 Actuals	2022 Increase	2022 Forecast
Residential - space heating load	93.8	126.9	33.1	171.8	51.0	222.8
Residential - non-space heating load	125.7	126.6	0.9	518.6	(13.5)	505.1
Residential Subtotal	**219.5**	**253.5**	**34.0**	**690.4**	**37.5**	**727.9**
Commercial	121.8	126.4	4.6	477.5	24.2	501.7
Large Industrial	34.3	38.4	4.1	153.8	9.7	163.5
Street Lighting	1.1	1.0	(0.1)	4.3	(0.5)	3.8
Total	**376.7**	**419.3**	**42.6**	**1,326.0**	**70.9**	**1,396.9**

Table 4 shows how the 2022 Residential space heating load forecast was determined by adding the revised projection from Table 3 to the 2021 actuals to arrive at 222.8 GWh.

b. Maritime Electric's load forecast for 2023 to 2025 is summarized in Table 5.

TABLE 5 Summary of Maritime Electric Sales Forecast (GWh)			
	2023	2024	2025
Residential space heating	229.8	244.3	258.8
Residential non-space heating before:	514.1	524.2	534.2
- Cumulative reduction due to DSM	(19.3)	(26.1)	(32.2)
- EV charging load	3.6	6.0	9.0
- Reduction due to rooftop solar	(4.7)	(5.6)	(5.9)
Commercial before:	523.3	527.6	532.2
- Cumulative reduction due to DSM	(22.4)	(30.0)	(36.9)
Large Industrial	163.5	168.0	168.0
Street Lighting	3.8	3.8	3.9
Total	**1,391.7**	**1,412.2**	**1,431.1**

Please see the response to IR-6 (a) for an explanation for the forecast methodology.

c. Please see the response to IR-6 (b) for a discussion of the changes made to the forecast methodology since it was reviewed by Grant Thornton in 2020.

d. In addition to the changes as described in the response to IR-8 (c), there has been a change in the assumptions about Residential space heating load for 2022. This is discussed in the responses to IR-8 (a) and IR-8 (e).

e. The 2022 Residential space heating load forecast provided in the Application includes actual sales for January to March 2022, which reflects a significant sales increase that appears to be driven by the price of furnace oil being higher than electricity in early 2022. This impact was not assumed to continue through the rate-setting period. The Company believes the price of furnace oil will normalize and residents who can will return to that source of space heating. Therefore, the space heating load forecast for 2023 to 2025 reflects a return to a normal usage per residence of electric space heating.

The continued increase in the Residential space heating load forecast from 2022 to 2023 and beyond, as shown in Table 6, is driven by population growth and the accompanying housing starts.

TABLE 6
Residential – Space Heating Load Variance

	2021	2022	2023	2024	2025
Residential - space heating load (GWh)	171.8	222.8	229.8	244.3	258.8
Variance %		30%	3%	6%	6%

IR-9 According to Table 4-4 (page 31 of the Application), Maritime Electric is forecasting a decrease in the General Service energy sales during the rate-setting period.

a) Is this decrease in energy sales due solely to efficiencyPEI's DSM programs (discussed on page 33 of the Application)?

b) If no, please explain other factors that may result in a decrease in General Service sales during the rate-setting period.

Response:

a. Yes, the decrease in General Service sales is due to efficiencyPEI's DSM programs. Table 1 shows that the estimated incremental annual energy savings due to the DSM programs are greater than the annual increases in usage estimated by the regression model, which uses the CBOC's forecast of real PEI GDP as the input.

TABLE 1
General Service Component of Sales Forecast

		2022	2023	2034	2025	2026
General Service before DSM (GWh)	**A**	516.5	523.3	527.6	532.2	538.3
Variance % due to GDP			*6.8*	*4.3*	*4.6*	*6.1*
Cumulative DSM savings (GWh)	**B**	14.8	22.4	30.0	36.9	42.8
Variance % due to DSM			*7.6*	*7.6*	*6.9*	*5.9*
Forecast of General Service Sales	**C = A-B**		**500.9**	**497.6**	**495.3**	**495.5**

The cumulative DSM savings was based on the Business As Usual ("BAU") scenario in the PEI Energy Efficiency Potential Study prepared by Dunsky Energy Consulting. The BAU scenario has the lowest DSM energy savings of the three scenarios presented in the study. The BAU scenario assumed a continuation of the level of subsidies incorporated in efficiencyPEI's first three-year plan. At the time the forecast was prepared, efficiencyPEI's second three-year plan had not yet been filed with the Commission.

b. Please see the response to IR-9 (a).

IR-10 On page 32 of the Application, lines 5 to 6, Maritime Electric states that "*a number of factors have contributed to the historical increases in residential sales year over year, some of which are not expected to continue through the rate-setting period*."

a) What are the factors that Maritime Electric is referring to and why are they not expected to continue through the rate-setting period?

Response:

Lines 5 and 6 on page 32 of the Application refer to the increases in Residential load for 2020 and 2021 as compared to 2019.

A factor that contributed to increases in Residential non-space heating load during 2020 and 2021 was the impact that working from home due to pandemic restrictions had on energy sales. At the time the forecast was prepared, pandemic restrictions were largely removed and were not expected to be reinstated; therefore, the impact of pandemic restrictions on Residential non-space heating load was not expected to continue through the rate-setting period.

A factor that contributed to an increase in Residential space heating load in the latter part of 2021, and into early 2022, was an increase in furnace oil prices. It appears that some customers resorted to short-term measures, such as plug-in electric heaters, to reduce furnace oil usage. Furnace oil prices are expected to moderate, and this increase in Residential space heating load was not expected to impact the rate-setting period, as discussed in response to IR-8.

IR-11 According to Table 4-5 (page 34 of the Application), Maritime Electric is forecasting a 40 percent (approximate) increase in both Transmission and Distribution operating costs and General and Administrative operating costs between 2019 and 2025.

a) Please provide justification for a 40 percent increase in operating costs over a 6 year period.

b) What measures has Maritime Electric taken to reduce or minimize operating costs during the rate-setting period?

Response:

a. Appendix C to the Application includes a detailed discussion of all operating costs. In particular, Section C.2, beginning on page 21, discusses transmission costs; Section C.3, beginning on page 29, discusses Open Access Transmission Tariff ("OATT") costs; Section C.4, beginning on page 32 discusses distribution costs; and Section C.6, beginning on page 50, discusses general and administrative costs.

The following response will first address the increase in the transmission and distribution costs and then the increase in general and administrative costs.

Transmission and Distribution

As demonstrated in the following table, transmission and distribution costs have increased 44 per cent over a six-year period, which is driven by OATT and distribution costs, which combined accounts for 80 per cent of the variance.

TABLE 1 Transmission and Distribution Costs			
($000)	**2019 Actual A**	**2025 Forecast B**	**Variance C = B - A**
Transmission	671	1,386	715
OATT	8,520	11,813	3,293
Distribution	5,031	7,607	2,576
Other	2,294	3,009	715
Total	**16,516**	**23,815**	**7,299**
Variance %			**44%**

<u>OATT</u>

The OATT costs account for 45 per cent of the variance. The increase is primarily driven by changes to the approved OATT rates effective September 1, 2022, as approved by Commission Order UE22-04, along with a forecast increase in transmission system load.[22]

<u>Distribution</u>

Distribution costs account for 35 per cent of the variance, which is driven primarily by vegetation management and inflation.

22 The Company's average monthly transmission load was 206.0 MW in 2019 and is forecast to increase to 237.9 MW by 2025.

In the Application, the Company submitted a plan to expand its vegetation management program to be more in line with industry best practice, which accounts for $1.5 million of the increase. Justification to expand the vegetation management program was provided in Appendix E of the Application.

Inflation at an average annual rate of 2.5 per cent over the six-year period increased distribution costs by approximately $0.8 million.[23]

The remaining increase in distribution costs of $0.3 million translations to an annual increase of one per cent, which is primarily due to engineering and line maintenance staffing changes.[24] These increases are justified to support increases in load growth and in the investment in distribution assets over the six-year period between 2019 and 2025.[25]

Transmission

Transmission costs account for 10 per cent of the variance, which is driven primarily by vegetation management and inflation.

In the Application, the Company submitted a plan to expand its vegetation management program to be more in line with industry best practice, which accounts for $0.5 million of the increase. Justification to expand the vegetation management program was provided in Appendix E of the Application.

Inflation at an average annual rate of 2.5 per cent over the six-year period increased transmission costs by approximately $0.1 million.[26]

The remaining increase in transmission costs of $0.1 million translations to an annual increase of approximately 2.5 per cent, which is primarily due to engineering and line maintenance staffing changes along with increased transmission substation costs related to an increase in the number of substations in recent years.[27] These increases are justified to support increases in load growth and in the investment in transmission assets over the six-year period between 2019 and 2025. [28]

Other

Other costs account for 10 per cent of the variance, and include insurance, property tax and employee training. A detailed discussion of these costs was provided in Section C.5 of Appendix C to the Application. The increase is driven primarily by property tax.

23 In comparison, more recently, the average annual inflation was 3.77 per cent from July 2019 to July 2022.

24 $0.3 million / $5.031 million x 100 / 6 years = 1.0 per cent per year

25 Load growth is forecast to increase by 11 per cent from 2019 to 2025, which is calculated on 2019 actual sales of 1,286.9 GWh compared to 1,431.1 GWh forecast for 2025. Investment in transmission assets is forecast to increase by 52 per cent from 2019 to 2025, which is calculated on 2019 net book value of transmission assets of $94.0 million compared to $142.9 million by 2025.

26 In comparison, more recently, the average annual inflation was 3.77 per cent from July 2019 to July 2022.

27 $0.1 million / $0.671 million x 100 / 6 years = 2.5 per cent per year

28 Load growth is forecast to increase by 11 per cent from 2019 to 2025, which is calculated on 2019 actual sales of 1,286.9 GWh compared to 1431.1 GWh forecast for 2025. Investment in distribution assets is forecast to increase by 26 per cent from 2019 to 2025, which is calculated on 2019 net book value of distribution assets of $265.2 million compared to $333.9 million by 2025.

Property tax is forecast to increase by $0.6 million from 2019 to 2025. Property taxes relate to the land on which the Company's transmission and distribution assets are located. Property tax is levied as either a tax on physical properties based on their assessed values or a revenue-related tax calculated at 1.0 per cent of the Company's annual revenue from the prior year. During the rate-setting period, property taxes are forecast to increase by 5.2 per cent annually, which is based on 1.0 per cent of the prior years' forecast revenue.

In comparison, actual increases from 2019 to 2021 have averaged 3.9 per cent annually, which was materially in accordance with approved forecasts.

General and Administrative Costs

As demonstrated in the following table, general and administrative costs have increased 47 per cent over a six-year period, which is driven by inflation and Corporate Services and Support costs.

TABLE 2
General and Administrative Costs

($000)	2019 Actual A	2025 Forecast B	Variance C = B – A
Customer Service	1,923	2,277	354
Finance and Accounting	1,392	1,512	120
Corporate Communications	414	861	447
Information Technology	695	987	292
Regulation	1,065	1,385	320
Directors' Fees	365	563	198
General Property	692	872	180
Corporate Services and Support	2,938	5,515	2,577
Total	**9,484**	**13,972**	**4,488**
Variance %			**47%**

Inflation

Assuming an average inflation rate of 2.5 per cent per year over this six-year period, inflation accounts for an increase of $1.5 million, or 33 per cent of the total increase.[29]

Corporate Services and Support

Corporate Services and Support costs accounts for 57 per cent of the total General and Administrative cost increase. In 2019 Corporate Services and Support costs included an amortization credit (i.e., offset to expense) related to an actuarial gain on employee future benefit costs of $2.0 million in 2019.[30] Excluding this credit, Corporate Services and Support costs were $4.9 million in 2019, resulting in an increase of only $0.6 million over

[29] In comparison, the average annual inflation from July 2019 to July 2022 was 3.77%, resulting in inflation of 11.75% over the three-year period.

[30] In 2015 the Company made a change to the retiree health benefits plan that resulted in an actuarial gain on past service costs of approximately $10 million. This actuarial gain was being amortized over five years; from mid-2015 to mid-2020, which was the average remaining period to full eligibility for active members as required by Accounting Standards for Private Entities. The last full year of amortization of this gain was in 2019.

the six-year period to 2025, which is due primarily to inflation.

Remaining Increase in General and Administrative Costs
Excluding the impact of inflation and the change in Corporate Services and Support costs, the remaining increase in General and Administrative costs is $0.9 million.

Corporate communications costs are forecast to be $0.38 million higher due to: i) the addition of a sustainability engineer and an annual tree planting campaign;[31] and ii) annual costs related to community outreach that were deferred as part of the Company's approved demand side management program in 2019.

Information technology costs are forecast to increase by $0.18 million primarily to respond to increasing cybersecurity risks.

Regulation costs are forecast to increase by $0.15 million due to the addition of a regulatory analyst in 2021 and the salary progression of three newly promoted team members in 2018.

Directors' fees are forecast to increase by $0.14 million to reflect the periodic market review of the directors' compensation plan.

b. When developing the operating cost forecast for the rate-setting period, the Company sought to balance its requirement to operate, maintain and secure the electrical system in accordance with good utility practice with the desire to manage customer rate impacts.

At times, the requirement to provide utility service necessitates the incurrence of higher costs. For example, with respect to transmission and distribution costs, the budget is impacted by load growth and increased investment in the electrical system.[32]

Nonetheless, the Company always endeavors to reduce costs or minimize cost increases. Some measures taken to reduce or minimize operating costs during the rate-setting period include the following:

- The Company has taken a conservative approach by estimating inflation over the rate-setting period at 2.5 to 3.0 per cent, as discussed in the response to IR-13(b), despite recent trends in inflation. By comparison, Statistics Canada reported the year over year inflation for PEI reached a high of 11.1 per cent in May 2022 and the average annual inflation from July 2019 to July 2022 was 3.77 per cent. This means that the Company is assuming the risk of inflationary cost pressures above 2.5 to 3.0 per cent in order to manage rate increases for customers.
- The Company critically reviewed recent operating costs to identify changing trends and/or anomalies to ensure forecast costs during the rate-setting period are reasonable. Some examples of cost savings realized between 2019 actual costs and 2025 forecast costs include:

31 Sustainability activities are further discussed in response to IR-30.

32 The Company's sales are expected to increase by 11 per cent by 2025 compared to 2019, which impacts the design of the electrical system, and the net book value of transmission assets is expected to increase by 52 per cent and distribution assets by 26 per cent by 2025 over 2019.

- Higher transformer maintenance costs in 2019 was identified as an anomaly, due to damage sustained to transformers during post-tropical storm Dorian.
- A downward trend in actual postage costs, as a result of the Company's campaign to move customers to electronic billing, was reflected in forecast postage costs.
- A labour cost reduction was forecast in Finance, reflecting the retirement of a full-time employee in 2020 who was not replaced.

IR-12 According to Table 4-6 (page 36 of the Application), Maritime Electric is forecasting capital contributions of $10.25 million in 2024 and $8.75 million in 2025.

a) Please explain the increased capital contributions in 2024 and 2025.
b) Do the capital contributions in Table 4-6 include Government funding available for the CIS and advanced metering infrastructure?

Response:

The response to IR-12 is being deferred until the Commission reaches a decision on the Company's Application for Confidentiality filed on October 31, 2022.

IR-13 On page 38 of the Application, lines 5 to 9, Maritime Electric states that the cost of service elements are forecast based on the methodology used in the previous GRA and reviewed by Grant Thornton.

a) Please explain any changes in the methodology since it was reviewed by Grant Thornton in 2020.
b) Please provide an explanation of any material change in the inputs or assumptions since the methodology was reviewed by Grant Thornton in 2020.

Response:

a. The Company's cost of service forecasting methodology has not materially changed since the review by Grant Thornton in 2020.

b. Changes to the underlying load and sales forecast assumptions are provided in response to IR-8 (a) and (b).

Changes in Energy Supply Cost assumptions include:

- Provincial Debt Repayment Costs reflect the annual costs recoverable from customers on behalf of the Province of PEI related to expected financing arrangements for costs deferred and assumed by the Province under the PEI Energy Accord. These costs are currently recovered from customers as a separate rate rider outside of the Company's revenue requirement. In accordance with Order UE20-06, the Company is proposing to include these costs in the Company's revenue requirement beginning on March 1, 2023 and no longer collect these amounts as separate rate rider. Further, the Company is not proposing to include these costs in the Energy Cost Adjustment Mechanism ("ECAM").
- Addition of energy generated from three new Commercial Renewables as discussed in the response to IR-14.
- The forecast energy for non-commercial renewables has been increased to reflect the penetration of roof-top solar installations.
- Energy Purchase Agreement ("EPA") prices forecast reflect the extension of the EPA agreement as discussed in the response to IR-14.

Changes in operating cost assumptions include:

- Expansion of the vegetation management program to improve reliability and safety and to be in line with industry best practice, as discussed in Appendix E of the Application.
- Updated inflation rates were based on management's best estimates, which were heavily influenced by:

Bank of Canada Consumer Price Index ("CPI")	
2021 Annual Average Inflation (2020 to 2021)	3.72%
Five-Year Annual Average Inflation (2016 to 2021)	2.00%

IR-14 On page 38 of the Application, lines 27 to 29, Maritime Electric states that energy supply costs account for approximately 46 percent of the Company's forecast rate increase.

a) Please confirm when the current Energy Purchase Agreement with NBEM will expire.
b) Please explain why Maritime Electric's energy supply costs are forecast to increase during the rate-setting period.
c) Is the increase due to a change in the unit price for purchased energy or due to increased sales?
d) If the increase is due to increased energy sales, why does this impact the base rate for electricity?

Response:

a. The EPA with New Brunswick Energy Marketing ("NBEM") was extended to December 31, 2026 by an Amendment in October 2020.

b. Energy supply costs are determined by four primary assumptions: (i) total energy required by customers (i.e., energy sales); (ii) how much energy is provided by each energy source; (iii) the cost of each energy source; and (iv) required capacity purchases.

Energy sales are forecast to increase over the rate-setting period, as discussed in response to IR-8 (b). This accounts for approximately 55 per cent of the increase in energy supply costs from 2019 to 2025.

The remaining increase in energy supply costs is driven by the source price. A summary of the total cost of energy by source was provided in Table 5-2 in the Application, and further discussed as follows.

First, the cost of the energy forecast to be purchased under the EPA is subject to the pricing terms of the EPA. Second, not all of the Company's energy requirements are purchased under the EPA; other sources include the Point Lepreau Nuclear Generating Station ("Point Lepreau"), renewables sources, and Company-owned generation. Finally, forecast energy costs also include transmission charges, cable interconnection costs, energy control centre costs, Provincial debt repayment costs and other energy costs.

With respect to the EPA, energy prices are forecast to increase over the rate-setting period in two ways. First, the base price per MWh increased on March 1, 2022 by 1.2 per cent and will remain in effect for the remaining term of the EPA. The base price per kWh was based on Maritime Electric's forecast energy requirement at the time the contract was negotiated in October 2020.

Second, the EPA includes a ratchet pricing clause, which adds a premium per MWh if the actual energy required from March to February of the prior year is more than 6 per cent lower or 8 per cent higher than the forecast energy requirement negotiated in the EPA.[33] The premium escalates with every 1 per cent change in the variance, and if the ratchet is

[33] Replacement energy purchased due to unplanned or extended Point Lepreau outages are exclude from the ratchet price clause.

triggered, the premium is applied to the total energy purchased under the EPA in a given period. A premium ratchet of 1.5 per cent was triggered for March 1, 2022 to February 28, 2023, primarily as a result of the delayed in-service date of the proposed 30 MW wind farm requiring the purchase of an additional 10 per cent more energy from NB Power for that period. It is assumed that the ratchet will be triggered to varying degrees during the rate-setting period, as discussed in the confidential response to IR-18.

With respect to Point Lepreau, the annual costs under the participation agreement and anticipated output from the facility are based on forecasts provided by NB Power. In years when there are planned outages at the facility, the energy forecast includes the anticipated cost of replacement energy during the planned outage. As indicated on line 7 on page 40 of the Application, a 50-day maintenance outage is planned for Point Lepreau in 2024, and the cost of replacement energy is included in the firm energy costs forecast under the EPA for that year. Further information on the cost of this replacement energy is included in the confidential response to IR-16 (a).

The energy supply costs also includes energy procured through commercial wind and solar contracts. The 92 MW of existing wind purchases from the PEI Energy Corporation ("PEIEC") are based on contract prices under the various Power Purchase Agreements that include annual escalation clauses. In addition, there are three additional renewable generation facilities expected to come on-line during the rate-setting period, as noted on Table 5-3 on page 41 of the Application and repeated in Table 14 for ease of reference.

Table 1
Commercial Wind and Solar
(Excerpt from Table 5-3)

Type of Facility	In-service Date	MW
Slemon Park Solar Micro-Grid	January 1, 2023	10.0
New Wind Facility	January 1, 2024	30.0
New Wind Facility	January 1, 2025	40.0

In the absence of a signed Power Purchase Agreement, the unit price for energy generated from these new facilities was assumed to be at the purchase price of Hermanville, the last wind farm to be added on PEI. The Hermanville energy purchase price is higher than the per unit energy price under the EPA, as disclosed in the Company's confidential response to IR-15.

Energy supply costs are forecast to increase as a result of customer-owned rooftop solar installations. Net-meter energy purchases from these small-scale customer-owned generation is expected to increase by 220 per cent by 2025 over 2021 levels. This energy is purchased at the retail price of electricity, as legislated under the *Renewable Energy Act,* and is significantly more expensive than energy purchased under the EPA.

The cost of Company-owned generation is also forecast to increase over 2023 to 2026 at an average of 2.0 per cent (see response to IR-20); however, this cost is small portion of the total energy supply cost.

By 2025, short-term capacity purchases are forecast to increase by 78 per cent over 2021 levels. The increase reflects the replacement of on-Island capacity lost due to the retirement of the Charlottetown Thermal Generation Station in 2021 and the impact of increasing peak demand over the rate-setting period.

c. See response to part (b).

d. The increase in energy supply costs due to increased sales does not impact the base energy cost per kWh included in ECAM over the rate-setting period.

The annual base rate for electricity is a unit cost per kWh calculated as follows:

$$\text{Base Energy Cost} = \frac{\text{Total Energy Supply Costs as Approved in UE21-05 Schedule A}}{\text{Total Net Purchased and Produced Energy in kWh}}$$

Therefore, if the increase in total energy supply costs was due to increased sales volume alone, then the corresponding increase in the denominator would result in the same or similar base energy cost. A change in the base energy cost occurs when the price of energy procured or generated increases per kWh.

With respect to the basic energy charge included in customer rates, this portion of the energy charge is meant to recover the total forecast revenue requirement less other revenue as set out in Table 6-5 of the Application. To the extent that the base energy cost defined above increases year over year, this amount results in an increase in revenue requirement to be recovered through the basic energy charge to customers over the rate setting period.

In addition, any increase in energy supply costs that are not included in ECAM, as described in the Company’s response to IR-15 and quantified in Table 4 to that response, results in an increase in revenue requirement to be recovered through the basic energy charge to customers.

IR-15 In Table 5-2 (page 40 of the Application), Maritime Electric has provided the Energy Supply Cost by Source. Please provide the unit cost for each of the energy sources listed in Table 5-2.

Response:

The response to IR-15 is being deferred until the Commission reaches a decision on the Company's Application for Confidentiality filed on October 31, 2022.

IR-16 Maritime Electric is forecasting a single 50-day outage at Point Lepreau for April to May 2024 (see page 41, lines 7 to 8).

a) What is the forecast cost of the 50-day outage?
b) Please calculate the rate impact of this outage for each rate class.
c) Please explain the financial implications of an extended outage.
d) Please confirm if the replacement energy for the 50 day outage is included in the 2024 forecast figures, and if so please provide forecast assumptions and calculations.
e) What measures has Maritime Electric taken to reduce or minimize outages at Point Lepreau?
f) Has Maritime Electric completed a cost versus benefit analysis of Point Lepreau taking into consideration the number of outages in recent years. If so, please provide this analysis.

Response:

The response to IR-16 is being deferred until the Commission reaches a decision on the Company's Application for Confidentiality filed on October 31, 2022.

IR-17 There have been a number of delays with the anticipated wind farms coming online.

a) Please elaborate further on the likelihood of the increased energy sourced by Wind & Other Renewables in Table 5-2 (page 40 of the Application) included in the 2024 and 2025 forecasts.

b) If the wind farms do not come online in the timeframe expected, please explain the potential impact.

Response:

a. There are three commercial renewable generation facilities expected to come on-line during the rate-setting period, as noted on Table 5-3 on page 41 of the Application and repeated in Table 1 in the response to IR-14.

The in-service dates provided were confirmed by the PEIEC in the latter part of 2021 and early 2022. The Company assumes that previous in-service dates provided by the PEIEC have not been met due to outstanding approvals. Given supply chain issues and labour shortages, the Company does share the Commission's concern that these in-service dates may not be attainable. However, this is the best information available to the Company.

b. A delayed in-service date for the proposed wind farms has the potential to impact whether ratchet pricing clause in the EPA is triggered. Given the confidential nature of the EPA, a detailed response to this IR is provided as part of the response to IR-18.

IR-18 On page 42 of the Application, lines 9 to 10, Maritime Electric states that the ratchet clause in the EPA was triggered in 2022, resulting in the requirement to purchase secure energy in 2023.

a) Please explain the ratchet clause, the financial impact on the 2023 forecast, and confirm this impact has been included in the forecast figures.

Response:

The response to IR-18 is being deferred until the Commission reaches a decision on the Company's Application for Confidentiality filed on October 31, 2022.

IR-19 On page 42 of the Application, Maritime Electric states that they are not forecasting to exceed the forecast load, with the exception of 2023 due to the ratchet clause in the EPA. However, Maritime Electric has also stated that they anticipate a 50-day shutdown of Point Lepreau in 2024, which will require replacement energy.

a) Please explain where the replacement energy related to the 2024 50-day shutdown of Point Lepreau is included in Table 5-2.

Response:

a. Replacement energy related to the 50-day planned outage in 2024 is included in the $77,269,000 figure as "Firm Energy" in Table 5-2.

Further information on the Point Lepreau planned outage in 2024 and the related replacement energy is provided in response to IR-16.

IR-20 Based on Table 5-2 (page 40 of the Application), the costs for CT1 and CT2 have more than doubled between 2019 and 2025. Please explain the reason for this increase.

Response:

The forecast costs for CT1 and CT2 have both fixed and variable components.

TABLE 1 CT1 and CT2 Costs ($000)							
CT1 and CT2	**2019 Actual**	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Labour	181	223	220	282	250	228	406
Contractors	2	-	-	4	4	5	5
Non-labour	27	24	47	107	72	73	77
Subtotal	**210**	**247**	**267**	**393**	**326**	**306**	**488**
Fuel	100	66	159	215	281	369	405
Total	**310**	**313**	**426**	**608**	**607**	**675**	**893**
Gross Generation (MWh)	200	93	358	550	750	825	908

Over 50 per cent of the increase in costs from 2019 to 2025 is due to fuel costs. Fuel costs are based on the generation shown in Table 1, which includes testing and required generation to meet load requirements. The Company forecast an increase in generation to meet load requirements over the rate-setting period based on experienced increases in NB Power hold-to-schedule requirements in 2021 and an expected increase in intermittent energy supply over the rate-setting period.[34] The forecast fuel price is based on the US Energy Information Administration Forecast of future projected fuel prices at the time Maritime Electric's forecast was prepared.

The remainder of the increase in costs from 2019 to 2025 is due primarily to labour costs, which reflects employees returning to CT1 and CT2 maintenance and production duties in 2025. Prior to 2025, employees are temporarily assigned to CTGS decommissioning activities. Costs previously shared between the four generation assets (i.e., CT1, CT2, CT3 and CTGS) are now allocated to the three remaining generation assets. While significant effort has been made to reduce the overall number of generation plant staff in conjunction with the retirement of the CTGS, a certain minimum level of staff must be retained in order to ensure the facilities are adequately maintained and can be operated safely and efficiently when they are called upon.

Note that, as a result of Order UE21-05, the fuel account is included in ECAM and the labour, contractors and non-labour accounts are excluded from ECAM.

[34] A hold-to-schedule can occur when the Company's actual hourly generation from intermittent renewable generation sources is lower than the scheduled output. When NB Power cannot supply the additional energy due to transmission constraints in southeast New Brunswick, the Company must run its own generation and hold to the scheduled energy to meet customer load.

IR-21 On page 48 of the Application, lines 2 to 3, Maritime Electric states that its forecast OATT costs assume new OATT rates are effective July 1, 2022. However, in Appendix C, page 31 (lines 9 to 11), Maritime Electric assumes that new OATT rates will be effective July 30, 2022.

a) Please clarify whether Maritime Electric has assumed an effective date of July 1st or July 30th for the new OATT rates.

b) What, if any, impact will an alternate effective date for the new OATT rates have on the General Rate Application and the rates proposed therein?

Response:

a. Maritime Electric has assumed an effective date of July 1, 2022 for the new OATT rates, as stated on page 48 of the Application.

b. On August 16, 2022, the Commission issued Order UE22-04 approving the proposed OATT update as filed effective September 1, 2022, as compared to an assumed effective date of July 1, 2022 in the Application. The two-month delay will decrease other revenue in 2022 by a small amount but is not expected to materially impact overall financial results for 2022.

Since the proposed changes to the energy charge are forecast to be effective March 1, 2023 and are based on 2023 revenue requirement, the two month delay in implementing new OATT rates in 2022 will have no impact on the proposed energy charges in this Application.

IR-22 Referring to Table 5-5 (page 45 of the Application), there are a number of significant variances between the 2021 actual and the 2022 forecast costs for transmission.

a) Please provide more detailed variance analysis between the 2021 actuals and the 2022 forecasts.

Response:

a. The variances between the 2021 actuals and 2022 forecast are summarized in the following table and the more significant variances are explained.

TABLE 15
Transmission Costs ($000)

	2021 Actual	2022 Forecast	Variance
Substations	69	80	11
Rights of Way	544	397	(147)
Line Maintenance	260	322	62
Line Control Devices	61	79	18
Engineering	143	187	44
Total	**1,077**	**1,065**	**(12)**

Rights of Way
The 2021 increase in rights of way costs was due to contractors hired to complete additional vegetation management. As discussed in Section 5.1.2 of the Application and Appendix E, the Company has identified an immediate need for enhanced vegetation management activities. In 2021, operating and finance cost savings were realized and optimally redirected to vegetation management to improve overall reliability for customers.

The 2022 forecast did not assume the 2021 level of vegetation management could be completed in 2022; however, the 2022 forecast is materially consistent with the 2021 forecast.

Line Maintenance
The variance was due primarily to fewer-than-expected weather-related outages in 2021. The 2022 forecast is materially consistent with the prior year forecast.

Engineering
The variance reflects a proportionate allocation of new positions, a Standards and Training Coordinator and a Technical Services Supervisor.

IR-23 Referring to Table 5-7 (page 48 of the Application), there are a number of significant variances between the 2021 actual and the 2022 forecast costs for distribution.

a) Please provide more detailed variance analysis between the 2021 actuals and the 2022 forecasts.

Response:

a. The variances between the 2021 actuals and 2022 forecast are summarized in the following table, and the more significant variances are explained.

TABLE 16 Distribution Costs ($000)			
	2021 Actual	**2022 Forecast**	**Variance**
Substations	109	122	13
Rights of Way	2,766	1,831	(935)
Line Maintenance	1,569	2,059	490
Line Control Devices	41	55	14
Transformers	659	637	(22)
Meters	165	190	25
Communication Systems	236	251	15
Supervisory SCADA	101	121	20
Engineering	385	442	57
Total	**6,031**	**5,708**	**(323)**

<u>Rights of Way</u>
The variance was due to higher vegetation management costs incurred in 2021, as discussed in the response to IR-22. In 2021, operating and finance cost savings were realized and optimally redirected to vegetation management to improve overall reliability for customers.

<u>Line Maintenance</u>
The variance was due primarily to fewer-than-expected weather-related outages resulting in lower over-time and double-time in 2021. In addition, an apprenticeship bootcamp and subsequent hiring of power line technician apprentices, which was originally planned for early in 2021, was postponed until the fourth quarter of 2021 resulting in lower-than-planned labour costs.

The 2022 forecast is higher than the prior year actual as weather-related outages were abnormally low in 2021. The 2022 forecast did not vary materially from the prior year forecast.

Engineering
The variance was driven by lower labour costs in 2021, which reflect a parental leave that was not backfilled. In addition, there were lower-than-planned training costs in 2021 as a result of pandemic-related travel restrictions.

The 2022 forecast does not vary materially from the prior year forecast.

IR-24 The weather normalization reserve ("WNR") has been in place for approximately 6 years on an interim basis. Maritime Electric is now requesting that the WNR be approved on a permanent basis for the rate-setting period and future years.

a) Please provide compelling evidence to support maintaining the WNR deferral account.

b) Please explain why it is reasonable to assume that the WNR will have a stable balance over the rate-setting period.

Response:

a. As indicated on page 83 of the Application, the purpose of the WNR is to stabilize electricity rates charged to customers by removing the volatility in sales and energy supply costs caused by temperatures relative to the 10-year historical averages, as measured by HDD. This aligns with a Principal of Public Utility Rates that customer rates should be stable.[35]

One reason to maintain the WNR deferral account is the continued penetration of electric space heating on PEI, partially as a result of Government incentives to install heat pumps. As the reliance on electric space heating increases, the potential volatility in sales and energy supply costs caused by variability in annual HDD will also increase.

A second reason is the unknown impact that climate change will have on annual HDD, which may cause greater variability in annual HDD compared to the 10-year historical average.

A third reason is the use of such a deferral account is accepted regulatory practice and serves to protect both the customer and the utility from the volatility in sales that is caused by variability in annual HDD.[36, 37] The following example illustrates this concept.

The Company's annual revenue requirement is recovered from customers based on an energy sales forecast, which is partially based on a 10-year historical HDD average. If winter temperatures are colder than forecast (i.e., colder than the 10-year average), then customers using electric space heating will consume more energy and the Company's sales and revenue will be higher than forecast. The WNR deferral account functions to defer this over collection of the Company's approved revenue requirement. Alternatively, if winter temperatures are warmer than forecast (i.e., warmer than the 10-year average), then customers using electric space heating will consume less energy and the Company's sales and revenue will be lower than forecast resulting in an under collection of the Company's approved revenue requirement. The WNR deferral account functions to ensure the Company has a reasonable opportunity to recover its approved revenue

[35] Principles of Public Utility Rates by Dr. James Bonbright are used by utilities to design rates and by regulators to assess the reasonableness of proposed rates.

[36] The WNR deferral aligns with a second Principle of Utility Rates that the aggregate of all customer rates and revenues must be sufficient to recover the utility's cost of service.

[37] P.U. Order No. 1 ordered that Newfoundland Power create a Weather Normalization Reserve and ATCO Gas, a division of ATCO Gas and Pipelines Ltd., received regulatory approval of a Weather Deferral Account in AUC Order 2008-113. A recent order by the Alberta Utilities Commission discusses ATCO Gas' weather deferral account: Decision 27415-D01-2022.

requirement from a sales volume perspective, and protects customers from an over collection of the revenue requirement when weather causes sales to increase.

b. Chart 5-1 on page 84 of the Application illustrates that actual HDD on PEI have cycled from being lower than to being higher than the 10-year average. Specifically, actual HDD in 2017 were lower than the 10-year average, actual HDD in 2018 and 2019 were higher than the 10-year average and actual HDD in 2020 and 2021 were lower. Maritime Electric believes that it is reasonable to assume this pattern will continue.

IR-25 On page 49 of the Application, lines 18 to 24, Maritime Electric is forecasting an increase of 2.9 percent annually for line maintenance costs.

a) Although Maritime Electric states that the forecasts for 2023 to 2025 are based on historical actuals adjusted for inflation, from 2019 to 2021, actual costs decreased by an average of 4.0 percent annually. Please explain.

b) Maritime Electric's forecast also "*assumes responding to weather-related outages based on the 10-year average*". Please explain what is meant by this, including the impact of the 10-year average on line maintenance costs during the rate-setting period.

Response:

a. Section C.4.3 of Appendix C to the Application provides a detailed variance analysis of distribution line maintenance costs. As discussed on page 37 of Appendix C, actual line maintenance costs in 2019 were 3 per cent lower than forecast due to a decrease in non-labour costs, partially offset by an increase in contractor costs. The non-labour variance was primarily due to lower-than-expected costs for materials and supplies and the contractor variance was primarily due to costs associated with post-tropical storm Dorian.

Actual line maintenance costs in 2020 were 12 per cent higher than forecast, driven by an increase in non-labour costs, which included approximately $100 thousand to repair accidental damage to third-party communications fibre that occurred while the Company was performing work on its own assets. The remaining variance was primarily due to the cost of pandemic-related safety measures.[38]

Actual line maintenance costs in 2021 were 23 per cent lower than forecast, driven by labour costs due primarily to fewer-than-expected weather-related outages resulting in lower over-time and double-time. In addition, an apprenticeship bootcamp and subsequent hiring of power line technician apprentices, which was originally planned for early in 2021, was postponed until the fourth quarter of 2021 resulting in lower-than-planned labour costs. The 2021 contractor and non-labour variances were due primarily to fewer-than-expected weather-related outages.

Based on the above analysis, it is not reasonable to expect line maintenance costs to continue to decrease. At a minimum, the Company expects the costs to increase by inflation, which supports the average annual increase of 2.9 per cent during the rate-setting period.

b. Line maintenance costs can be materially impacted by weather-related events. For example, as discussed in the response to part (a), actual line maintenance costs in 2021 were 18 per cent lower than in 2020 due to fewer weather-related events. When forecasting line maintenance costs, Maritime Electric considers the frequency and severity of weather-related events that occurred over the past 10 years when developing a forecast.

[38] Pandemic-related safety measures included vehicle rentals to maintain physical distancing while travelling to and from work sites, additional cleaning measures, purchase of masks, and portable washroom rentals.

The following table provides the distribution line maintenance costs for 2012 to 2021. The variability of costs illustrates the requirement to "normalize" the expected frequency and severity of weather-related events during a rate-setting period.[39]

TABLE 1
Distribution Line Maintenance Costs
($000)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1,116	983	1,609	1,588	1,632	1,644	1,866	1,805	2,145	1,569

[39] The concept of "normalizing" historical costs is further discussed in response to IR-27.

IR-26 On page 50 of the Application, lines 1 to 6, Maritime Electric is forecasting an average increase of 2.4 percent annually for line control devices. Although Maritime Electric states that the forecast for 2023 to 2025 reflects historical actuals adjusted for inflation, from 2019 to 2021, the cost for line control devices actually decreased by an average of 11.6 percent annually. Please explain.

Response:

Section C.4.4 of Appendix C to the Application provides a detailed variance analysis of distribution line control devices. As discussed on page 39 of Appendix C, actual line control device costs in 2019 and 2020 did not vary materially from forecast. Actual costs in 2021 were lower than forecast due to the mid-year replacement of an employee that was reassigned in 2019.

Based on the above analysis, it is not reasonable to expect the costs to continue to decrease by 8.9 per cent annually. At a minimum, the Company expects costs to increase by inflation, partially offset by labour efficiencies, thereby supporting the average annual increase of 2.4 per cent during the rate-setting period.

IR-27 On page 51 of the Application, Maritime Electric refers to a normalization of historical costs for both Communication Systems and Supervisory SCADA. Please explain why these cost items were normalized and others were not.

Response:

The normalization of historical costs refers to the removal of historical costs or savings that are not expected to recur when developing a forecast. Such an analysis was completed on all cost categories; however, only certain costs required a significant adjustment of historical costs to remove non-recurring costs or savings.

With regards to Communication Systems costs, actual costs from 2019 to 2021 increased by an average of 21.9 per cent, which was significantly above inflation. As discussed on page 43 of Appendix C to the Application, 2019 costs were lower than forecast due to employees being reassigned to other departments to assist with the lingering clean-up from post-tropical storm Dorian. When the 2020 and 2021 costs were compared to 2019, the variance is a significant increase that was not expected to continue. Therefore, historical costs for 2019 to 2021 were normalized to adjust for the reassignment of employees.

Similarly, with Supervisory SCADA costs, employees in this department were also reassigned to assist with the lingering clean-up from post-tropical storm Dorian and, therefore, the historical costs for 2019 to 2021 needed to be normalized.

IR-28 On page 52 of the Application, Maritime Electric is forecasting an increase in insurance cost of 5.5 percent annually "*as predicted by Fortis Inc.'s insurance specialist*" (see lines 5 to 6). Please provide evidence to support the forecast increase in insurance costs.

Response:

As discussed on page 52 of the Application, insurance is procured by Fortis Inc. on behalf of its group of companies. Fortis Inc.'s Director of Risk Management, Gordon Payne, with 20 years of experience in the insurance industry, works closely with an insurance broker, AON Risk Solutions, to secure sufficient insurance coverage for the Fortis group at competitive prices. Maritime Electric, being one of the smaller Fortis companies, benefits greatly from this group pricing.

The 2022 Risk and Insurance Management Report, prepared by Gordon Payne and attached as IR-28 - Attachment 1, discusses the current insurance market in comparison to recent years, concluding with a forecast increase of 5.5 per cent in 2022 for Maritime Electric's insurance premiums. In the absence of other information, the Company conservatively assumed this annual rate increase would continue during the rate-setting period.

IR-29 On page 53 of the Application, lines 17 to 18, Maritime Electric states that the 2023 to 2025 forecast for Customer Service costs has been reduced to reflect the 2019 and 2021 trend with respect to bad debt expense and damage claims. What trend is Maritime Electric referring to?

Response:

Section C.6.1 of Appendix C of the Application provides a detailed variance analysis of customer service costs, which includes bad debt expense and damage claims. As discussed on lines 5, 6, 9 and 10 of page 51, actual bad debt expense and damage claims in 2019 and 2020 were lower than expected. In addition, as discussed on lines 16 and 17 of page 51, actual bad debt expense in 2021 was higher than expected but was associated with one large customer that went into receivership in 2021 and is not representative of an upward trend. Taken together, the Company views this as evidence that the forecast for bad debt expense and damages claims should be reduced.

IR-30 On page 54 of the Application, lines 9 to 18, Maritime Electric details costs associated with sustainability activities, including an additional employee position in 2021 and a climate change study to be completed in 2022.

a) What are the operating and capital costs associated with sustainability activities?
b) Has Maritime Electric obtained Commission approval for these expenditures?
c) Is Maritime Electric seeking to recover these expenses from ratepayers?

Response:

a. Sustainability practices have always been important to Maritime Electric as they ensure that the Company continues to meet customers' needs without compromising future generations. In recent years, consumers and communities across the world have become increasingly more conscious of the need for corporate sustainable practices. PEI is no exception and Maritime Electric is required to provide service "as changing conditions require".[40] Therefore, responding to customers' expectations by enhancing sustainability practices is necessary.

With respect to sustainability activities, there have been no capital costs incurred and none are currently forecast to be incurred during the rate-setting period. The Company is completing a climate adaptation study, with the assistance of a third-party consultant, which will evaluate climate projections for PEI over the next 50 years and identify associated risks to Maritime Electric's infrastructure. This study is projected to cost $114,000, for which the Company received government funding of $57,000 via the Provincial Government's Climate Challenge Fund. The results of this study will be used to determine whether the Company's current design standards are sufficient to withstand the expected weather. At which point, the Company would submit any necessary design standard improvements for Commission approval as part of the annual capital budget application.

With respect to operating activities, a discussion of the sustainability activities was provided in Section C.6.3 on page 54 of Appendix C in this Application.

In 2020 the Company initiated the process of obtaining the Sustainable Electricity Company™ designation from Electricity Canada, which was awarded in early 2021. The majority of this process was completed by internal resources along with approximately $7,200 paid to a third-party auditor. Branding and marketing initiatives in 2021 cost approximately $2,500.[41]

b. The operating costs incurred were not material and were managed within the operating cost budgets approved by the Commission as part of the previous General Rate Application.

As Maritime Electric has not incurred any capital costs associated with sustainability activities and has not forecast any such capital costs for the rate-setting period, Commission approval was not necessary.

40 *Electric Power Act* Section 3
41 In 2021, the Company hired a Sustainability Engineer Coordinator to meet the ongoing reporting requirements for an annual cos to approximately $110,000, including benefits.

c. As Maritime Electric forecasts the continuation of sustainability activities, which will be recorded as operating expenses, the Company is seeking to recover these prudent expenses from rate payers.

When, and if, capital costs associated with sustainability activities are necessary, the Company will seek pre-approval as part of the annual capital budget application process.

IR-31 In Section 5.1.9 – Credit Metrics (pages 62 to 63 of the Application), Maritime Electric indicates that without the proposed rate increases, their credit metrics will decline significantly. What would be considered reasonably acceptable ratios within utility industry standards? Please provide examples.

Response:

Standard & Poor's ("S&P") uses cash flow/leverage analyses ("core ratios") to assess the cash flows of a regulated electric or gas utility, and then considers a number of interest coverage and payback ratios to enhance its understanding of the final financial risk profile of a company. S&P applies its "medial volatility" table as shown in Figure 1 below to assess the strength of a company's financial profile, and, depending on its evaluation of the company's credit metrics, S&P assesses the company's financial risk from "Minimal" to "Highly Leveraged".

S&P currently assesses Maritime Electric's financial risk as "Significant". Over the next two years, S&P expects Maritime Electric's stand-alone Funds From Operations ("FFO") to Debt ratio to reflect 16 to 19 per cent. S&P notes that the credit rating could be downgraded over the next 12 months if FFO to Debt is consistently below 16 per cent.

Figure 1
S&P Financial Risk Criteria

Table 18

Cash Flow/Leverage Analysis Ratios--Medial Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest (x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	50+	less than 1.75	10.5+	14+	40+	30+	18+
Modest	35-50	1.75-2.5	7.5-10.5	9-14	27.5-40	17.5-30	11-18
Intermediate	23-35	2.5-3.5	5-7.5	5-9	18.5-27.5	9.5-17.5	6.5-11
Significant	13-23	3.5-4.5	3-5	2.75-5	10.5-18.5	5-9.5	2.5-6.5
Aggressive	9-13	4.5-5.5	1.75-3	1.75-2.75	7-10.5	0-5	(11)-2.5
Highly leveraged	Less than 9	Greater than 5.5	Less than 1.75	Less than 1.75	Less than 7	Less than 0	Less than (11)

S&P assesses both business and financial risk in assigning a credit rating. S&P recently reduced Maritime Electric's business risk ranking from "Excellent" to the high end of "Strong" but maintained the issuer rating on the Company at BBB+. Figure 2 shows the credit metrics that align with the business and financial risk assessment of a company.

Figure 2
S&P Anchor Assessment Criteria

Combining The Business And Financial Risk Profiles To Determine The Anchor

	--Financial risk profile--					
Business risk profile	**1 (minimal)**	**2 (modest)**	**3 (intermediate)**	**4 (significant)**	**5 (aggressive)**	**6 (highly leveraged)**
1 (excellent)	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
2 (strong)	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
3 (satisfactory)	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
4 (fair)	bbb/bbb-	bbb-	bb+	bb	bb-	b
5 (weak)	bb+	bb+	bb	bb-	b+	b/b-
6 (vulnerable)	bb-	bb-	bb-/b+	b+	b	b-

What is considered reasonably acceptable credit ratios within the utility industry varies from company to company, because it depends in part on the business risk assessment as well as the credit metrics. In Concentric's experience, BBB+ is considered the minimum acceptable credit rating in Canada, and A- or better is often targeted. The market for bond securities lower than A- is relatively limited by comparison, which can lead to greater issuance costs, especially when markets are stressed.

IR-32 There appears to be a discrepancy between Table 5-10 (page 56 of the Application) and Table 5-30 (page 81 of the Application). Although Table 5-10 has a 2022 forecast RORA balance of $506,000, Table 5-30 has a 2022 forecast RORA balance of $500,000. Please clarify and explain.

Response:

Included in the Rate of Return adjustment is the forecast accrued interest for the January 1 to December 31, 2022 period of $6,000, and the forecast 2022 RORA of $500,000 for a total of $506,000 that is referenced in Table 5-10.

Table 1
Rate of Return Adjustment ($000)

Description	Reference	Total
Accrued Interest - January 1 - December 31, 2022	C – Table 5-30	6
Forecast 2022 RORA	D – Table 5-30	500
Rate of Return Adjustment for Table 5-10	**C + D**	**506**

IR-33 Please provide a detailed calculation, including all inputs and assumptions, for the revenue shortfall account for 2022 and 2023.

Response:

The original 2020 revenue shortfall approved by the Commission in Order UE20-06 was $2.76 million. The rate adjustments approved in the Order proposed collecting this amount in revenue requirement over a fourteen month period amortization period, from January 1, 2021 to February 28, 2022.

Subsequent to Order UE20-06, on January 22, 2021, the Commission issued a letter of direction requiring the Company to issue bill credits to customers for December 2020 consumption billed in 2022, and to provide a full reconciliation of the bill credits and the impact on the revenue shortfall account. On August 11, 2021, the Company issued a letter to the Commission providing a final reconciliation of bill credits to customers and 2020 revenue shortfall including a true-up adjustment of $282,966. The Commission issued a letter to Maritime Electric on September 10, 2021 accepting the reconciliation provided.

The 2021 true-up of $282,966 was not included in the revenue requirement upon which the rates approved in Order UE20-06 were set, as the amount was not known at that time. This amount was, therefore, set aside until the next rate-setting period to be recovered from customers.

TABLE 1 2020 Revenue Shortfall		
Original 2020 Revenue Shortfall Approved UE20-06 ($)	A	2,755,214
Original Amortization Period - January 2020 to February 2022 (# months)	B	14
Monthly Amortization of Original 2020 Revenue Shortfall ($)	C = A / B	196,801
Additional Collections - March 1, 2022 to February 28, 2023 (# months)	D	12
Deferral of Over Collection ($)	E = C x D	2,361,612
2021 True-up Adjustments[42] ($)	F	(282,966)
Forecast RORA, February 28, 2023 from Table 5-31 ($)	G	(52,949)
Forecast 2020 Revenue Shortfall, February 28, 2023 ($)	H = E + F + G	**2,025,697**

The Company is proposing that the balance of the Revenue Shortfall shown in Table 19, of $2.03 million, be returned to customers as a rate rider from March 1, 2022 to February 28, 2023. The calculation of the rider is provided in Table 5-31 of the Application and shown in Table 2 for reference.

TABLE 2 Proposed Revenue Shortfall Refund		
Forecast Revenue Shortfall Balance, February 28, 2023 ($)	A	2,025,697
Forecast Sales - March 1, 2023 to February 28, 2024 (kWh)	B	1,396,277,700
Proposed Refund ($/kWh) – March 1, 2023 to February 28, 2024	**C = A/B**	**0.00145**

42 See Table 4 in the Company's Letter to the Commission dated on August 11, 2021 re: Final Reconciliation of Bill Credits Issued to Customers and 2020 Revenue Shortfall.

IR-34 Table 5-19 (page 70 of the Application) details actual and forecast dividends for 2019 to 2025.

a) The Table states that it is in $ millions. Is this correct?
b) Please explain why the payout of regulated dividends fluctuates significantly year over year.

Response:

a. No, the heading for Table 5-19 references "$ millions" in error; the Table heading should reference "$ thousands".

b. The annual forecast for dividends is determined based on maintaining the Company's equity ratio within the range required under Section 12.1 of the *Electric Power Act*:

> *12.1 Common equity*
>
> *Maritime Electric Company, Limited shall, as determined in accordance with generally accepted accounting principles,*
> *(a) maintain at all times not less than 35 per cent of its capital invested in the power system in the form of common equity; and*
> *(b) ensure that, for the year, not more than 40 per cent of its capital is invested in the power system in the form of common equity. 2003, c.3, s.6; 2015,c.25,s.3.*

The forecast for 2022 through 2025 reflects the dividends required to comply with the second criteria that not more than 40 per cent of capital is invested in the power system in the form of common equity. The amounts fluctuate from year to year based on the equity investment required to deliver the capital program as set out in in Table 4-6 of the Application.

IR-35 In Table 5-27 (page 78 of the Application), Maritime Electric sets out the Proposed ECAM Rate Adjustment to Customers' Bills Effective March 1 in each of 2023 to 2025. Maritime Electric provides the forecast ECAM balance for December 31 of the prior year, as well as the forecast sales for March 1 to February 28.

a) Do the proposed ECAM rate adjustments include the ECAM collection amounts recovered from January 1 to February 28 of each year?

Response:

a. Yes, annual collections are included in the ECAM rate adjustment from Table 5-27. Table 5-27 and an excerpt from Table 5-28 of the Application are repeated below to illustrate.

As shown below, line A from Table 5-27 agrees to Line J from Table 5-28, which includes an annual ECAM collected through rate adjustment amount on Line F.

TABLE 5-27
Proposed ECAM Rate Adjustment to Customers' Bills Effective March 1

		2023	2024	2025
Forecast ECAM Balance, December 31 of Prior Year ($000)	**A**	**6,791**	**4,482**	**3,282**
Forecast Sales - March 1 to February 28 (GWh)	B	1,396.3	1,416.7	1,436.1
Proposed March 1 ECAM Rate Adjustment - $/kWh (rounded)	**C = A/B**	**0.00486**	**0.00316**	**0.00229**

Excerpt from Table 5-28
Summary of Annual Activity in ECAM ($000)

		2022 Forecast	2023 Forecast	2024 Forecast
Annual Deferral to ECAM	E	5,846	4,219	3,746
Annual ECAM Collected thru Rate Adjustments	**F**	**4,486**	**6,528**	**4,946**
ECAM Account Opening Balance January 1	G	5,431	6,791	4,482
ECAM Closing Balance December 31	**J = E - F + G**	**6,791**	**4,482**	**3,282**

IR-36 In Table 5-31 (page 83 of the Application), please explain why Maritime Electric is using the forecast sales from March 1, 2022 to February 28, 2023 to calculate a rate rider that is intended to be refunded from March 1, 2023 to February 29, 2024.

Response:

The dates on the forecast sales line were incorrect in the original filing of the Application. Please see below the amended table, with dates corrected on Line B to March 1, 2023 to February 28, 2024.

TABLE 5-31 **Proposed Revenue Shortfall Refund per kWh to be applied to Customers' Bills** **Effective March 1, 2023 to February 28, 2024**		
Forecast Revenue Shortfall Balance, February 28, 2023 ($)	A	2,025,697
Forecast Sales - March 1, 2023 to February 28, 2024 (kWh)	B	1,396,277,700
Proposed March 1, 2023 Refund ($/kWh)	**C = A/B**	**0.00145**

IR-37 In Table 5-33 (page 89 of the Application), do the calculations include the approved extension of the EE&C Plan? Please include all inputs, assumptions and calculations.

Response:

Table 5-33 is provided below for reference in the response.

TABLE 5-33 **Proposed EE&C Plan Collections** **March 1, 2023 to February 29, 2024**		
Forecast Sales - March 1, 2022 to February 28, 2023 (kWh)	A	1,395,847,900
Approved Rate Rider ($/kWh)	B	0.0013
Forecast Collections - March 1, 2022 to February 28, 2023 ($000)	**C = A x B**	**1,815**
Proposed Funding Required for PEIEC EE&C Plan ($000)	D	(869)
Forecast Overcollection, March 1, 2022 to February 28, 2023 ($000)	**E = C - D**	**946**

Table 5-33 assumes the following:

- The continuation of the existing rate rider of $0.0013 per kWh (line B) for the PEIEC Energy Efficiency and Conservation ("EE&C") funding from Maritime Electric customers until March 1, 2023. This will result in in collections of $1.8 million (line C) from Maritime Electric customers for this period based on forecast sales of 1,395.8 GWh (line A).

- The proposed EE&C Plan will be approved as filed with respect to the required collection amounts from Maritime Electric customers. The funding amounts required from Maritime Electric customers is provided in Table 3 on page 8 of Appendix A of the PEIEC Application. The total funding required in the Application over the three-year period is $2,604,848 and Maritime Electric has assumed that this will be collected as summarized in Table 1 below.

TABLE 1 **PEIEC Annual Funding**	
Funding Year	**Funding ($000)**
2022/2023 (Line D of Table 5-33)	869
2023/2024	868
2024/2025	868
Total	**2,605**

As shown in Table 5-33 of the Application, this will result in a forecast overcollection of $946,000 from March 1, 2022 to February 28, 2023. The Company is proposing that this forecast overcollection be used to reduce the funding requirement and the corresponding collection rate for March 1, 2023 to February 28, 2024 to nil. The remaining overcollection balance of $78,000 would then be used to reduce the funding amount to be recovered from March 1, 2024 to February 28, 2026 to $790,000.[43]

The proposed EE&C Plan does not extend to the final year of Maritime Electric's rate-setting period but it is reasonable to assume that demand side management ("DSM") programs will be extended as electrification of home heating and transportation continues. Therefore, the Company is proposing that the estimated gross funding requirement for 2024/2025 under the proposed EE&C Plan of $1,732,000 be used to estimate the requirement for the period March 1, 2025 to February 28, 2026.[44]

Table 5-34 of the Application, provided below for ease of reference, summarizes the Company's proposal to collect funding requirements from customers and the proposed collection rate over the rate-setting period.

TABLE 5-34
Proposed EE&C Plan Collection Requirements and Rate Rider
March 1 to February 28

	2023/24	2024/25	2025/26
Forecast Collection Requirement ($000)	-	790	1,732
Forecast Sales (kWh)	1,396,277,700	1,416,675,800	1,436,087,300
Collection rate ($/kWh)	-	0.00056	0.00121

In the proposed EE&C Plan, the PEIEC has suggested that the Company remit a fixed monthly amount to the PEIEC with any over or under collections due to sales fluctuations to be held in a regulatory deferral account to be managed by the utility. Should the Commission approve this change, the Company is proposing that such a change become effective March 1, 2023 and reflect a true-up of the balance of any additional over and under collections that would be used by the PEIEC to reduce future funding requirements as proposed in this Application.

43 Total over collection of $946,000 less $868,000 equals $78,000. The proposed EE&C Plan collection for March 2024 to February 2024 of $868,000 would be reduced by $78,000 to $790,000.

44 The estimate gross funding requirement of $1.7 million is based on the proposed EE&C Plan contribution amount before the overcollection from the previous EE&C Plan was applied. This is provided in Table 3 on page 8 of Appendix A of the PEIEC Application.

IR-38 Please provide any cost versus reliability analysis completed by Maritime Electric to support the proposed vegetation management plan.

Response:

Maritime Electric's analysis of cost versus reliability was provided as Appendix E to the Application.

Appendix E of the Application indicates that over 50 per cent of outages are caused by wind and tree contacts. In comparison, the industry average for tree-related outages from 2011 to 2021 was 14 per cent. More recently, Electricity Canada reported that in 2022 tree contacts accounted for 16 per cent of customer outages, which is still significantly below Maritime Electric's experience.[45] The recent and devastating effect that Hurricane Fiona had on trees, causing prolonged outages across the Island, is further evidence that the Company's vegetation management budget must be increased to improve reliability.

[45] Electricity Canada (formerly Canadian Electricity Association) 2021 Service Continuity Annual Report Overview

IR-39 Assuming the rates proposed by Maritime Electric in the Application are approved, please provide updated revenue-to-cost ratios for each of Maritime Electric's rate classes.

Response:

The proposed rate increases presented in the Application were applied evenly to the energy charge component of all rate classes, as illustrated by Table 7-1 on page 99 of the Application.[46] Therefore, the resulting revenue-to-cost ratios will be the same or materially the same as those in the 2020 Cost Allocation Study.

[46] The average annual variance in Table 7-1 is higher for the Large Industrial rate class due to a smaller portion of revenue being recovered through the energy charge component of this rate, compared to the other rate classes.

IR-40 Please provide a detailed breakdown of compensation paid, or forecasted to be paid, to MECL's senior management and executive position employees for the years 2019 to 2025 (inclusive). The breakdown should clearly show the compensation paid to each senior management and executive position, identifying the title of the position and a breakdown of the compensation paid by salary, bonus(es), stock option(s), and any other compensation paid or payable.

Response:

The response to IR-40 is being deferred until the Commission reaches a decision on the Company's Application for Confidentiality filed on October 31, 2022.

IR-41 Please confirm the dollar amount of compensation paid or forecasted to be paid to MECL's senior management and executive positions included in the revenue requirement for 2023 to 2025.

Response:

The response to IR-41 is being deferred until the Commission reaches a decision on the Company's Application for Confidentiality filed on October 31, 2022.

IR-42 In Appendix I – Financial Statements, Maritime Electric breaks out Fortis Inc. Head Office Costs (net of tax) which have been disallowed in calculating the annual revenue requirement and regulated return per Order UE09-02.

a) Please provide supporting documentation that supports the total expenditures and the amount that is excluded as it relates to Fortis Inc. admin charges.
b) Please describe the process followed to determine the amount that should be excluded and the supporting calculation for the amount excluded in the 2023 to 2025 forecast.

Response:

a. Fortis Inc. Head Office Costs are provided by Fortis Inc., in preparation of Maritime Electric's five-year business plan, which is updated annually. Please see IR-42 - Attachment 1 for the March 31, 2021 memo from Fortis Inc. confirming estimated Head Office Costs ("Corporate Recoveries") for the 2021 to 2025 years.

The following table provides the administrative charges used in preparation of the Application.

TABLE 1 Fortis Inc. Administrative Charges (Rounded)			
Year	**Fortis Inc. Cost**	**Tax (31%)**	**Net of Tax**
2021 (Actual)	617,000	(193,000)	424,000
2022 (Forecast)	671,000	(208,000)	463,000
2023 (Forecast)	690,000	(214,000)	476,000
2024 (Forecast)	723,000	(224,000)	499,000
2025 (Forecast)	728,000	(226,000)	502,000

The 2021 Head Office Costs in Table 1 are $11,000 higher than the preliminary forecast provided by Fortis Inc. Actual quarterly invoices totalling $617,000 for 2021 are provided in IR-42 - Attachment 2.

While these costs are excluded from the calculation of Maritime Electric's annual revenue requirement, as discussed in part b, they do provide a real benefit. As a member of the Fortis group of companies, Maritime Electric and its customers benefit from lower costs in such areas as cybersecurity, insurance, finance services and group purchases of materials and equipment. In addition, the network of knowledge and expertise across the Fortis group yields further benefits to the Company and PEI electricity customers through best practices and efficient information sharing. As a result, Maritime Electric's view is that these benefits far outweigh the costs recovered by Fortis and, as a result, the Fortis Inc. costs should be recoverable from electricity customers.

b. As discussed in response to part a), the forecast amounts for Fortis Inc. Head Office Costs, are provided by Fortis Inc. on an annual basis. The costs are based on the estimate of consultation and administrative support Fortis Inc. provides Maritime Electric on various aspects of business operations.

Pursuant to Commission Order UE09-02, these amounts are not recoverable and are excluded from revenue requirement for the purpose of establishing electricity rates and in the determination of regulated earnings for the year.

IR-43 In Appendix C to the Application, at page 16 (lines 2 to 4), Maritime Electric is forecasting a reduction to the interconnection lease payments, which reflects new lease terms effective July 1, 2022.

a) At the time the Application was filed, negotiations of the new lease terms were ongoing. Have the negotiations been finalized? If so, is there any change to the lease payments forecast in the Application?

b) Please provide particulars of the new lease terms, including any amendments to the existing interconnection lease agreement.

Response:

a. Yes, the negotiations have been finalized with an effective date of August 1, 2022.

The lease payments forecast in the Application compared to those finalized are provided in the following table.

Table 1
Interconnection Costs
($000, except %)

	GRA	Revised	Variance
2022 Forecast	3,050	2,758	(292)
2023 Forecast	2,882	2,343	(539)
2024 Forecast	2,882	2,343	(539)
2025 Forecast	2,882	2,523	(359)

There are two reasons for the variances per Table 1. First, the timing of the new payment schedule. The GRA assumed the new lease payment would be effective July 1, 2022. However, the new lease payment was effective March 1, 2022, and the revised forecast in Table 1 reflects a retroactive payment adjustment to March 1, 2022. This impacts the 2022 forecast only.

The second and primary reason for the variances is the application of $1.8 million in excess collections from customers to the monthly payments over a three-year term from September 2022 to August of 2025. When the Application was finalized in early 2022, the Company was not aware of the magnitude of excess collections from customers or whether the excess would be applied by the Province to the sinking fund or to future payments.[47]

The variance difference between the GRA forecast and revised forecast, as shown in Table 1, will not be additional income to the Company over the rate-setting period. The interconnection lease costs flow through ECAM and the variances will be returned to customers as part of the normal operation of this regulatory deferral account.

[47] Under Article 3.4 of the existing agreement, excess collections were to be deposited to the sinking fund. This Article has been amended under the new agreement.

b. As per Article 8.6 of the Agreement, an updated contribution ratio is required to be recalculated after the five-year period as per Section 3.2. In 2017 the contribution ratio was calculated to be 90.1 per cent for Maritime Electric and 9.9 per cent for the City of Summerside. The present five-year average (i.e., for 2017 to 2021) contribution ratio is calculated to be 90.5 and 9.5 per cent for Maritime Electric and City of Summerside respectively.

Ratepayer recoveries commenced before the cable interconnection project was completed. The project was completed under budget and the original taxpayer recovery rates resulted in excess collections, which were deposited in the Sinking Fund in accordance with Article 3.4 of the Cable Debt Collection Agreement. As of February 28, 2022, these excess collections totalled approximately $1.8 million. Provincial Government approval was granted to use the excess collections to reduce ratepayer recoveries over a three-year period from September 2022 to August 2025.

Table 2 shows recoveries from Maritime Electric customers from August 2022 to February 2027. In August 2022 the collection was reduced by the amounts over collected since March 2022, which will allow for the originally intended five-year adjustment schedule to remain. Starting in September 2022, for a period of 36 months, the collections will be reduced to allow the refund of $1.8 million in excess collections, which accumulated from March 2017 to February 2022. Once the excess collections have been fully refunded, the new monthly rate will be collected for the remainder of the five-year period from September 2025 to February 2027.

Table 2	
Period	**Monthly Payment ($)**
August 2022[48]	100,474.70
September 2022 to August 2025[49]	195,235.90
September 2025 to February 2027[50]	240,185.90

Amendments reflecting the above particulars of the new lease terms are included in Article 3.1, 3.3, 3.4, 6.4, 8.3, 8.4, 8.9, 8.10, Schedule A and Schedule B of the amended Debt Collection Agreement.[51]

48 New monthly payment of $240,185.90 less retroactive adjustment of $139,711. 20 ($27,942.24 per month for March to July 2022).

49 New monthly payment of $240,185.90 less return of excess collections of $44,950.00 per month. The excess collections are calculated as $1.8 million divided by 36 month reduction period multiplied by Maritime Electric's contribution ratio of 89.9%.

50 New monthly payment is calculated as total debt repayment of $235,398.78 plus 30,000.00 sinking for a total of $265,398.78 multiplied by Maritime Electric's new contribution ratio of 90.5%.

51 The amended Agreement has been drafted and is currently being reviewed by the parties thereto prior to signing.

IR-44 At pages IV-4 to IV-5 of the Depreciation Study, Gannett Fleming states:

> *During this year's study it became evident that Maritime Electric's actual retirement costs are trending much higher than contemplated in previous depreciation studies, as indicated by the accumulated GER balance. The Company has initiated an analysis of its use of standard distribution as the manner in which labor costs are allocated to capital, retirement and operating activities to assess the accuracy of the standard distribution allocation. The results of that analysis may affect the future recognition of labor costs to this GER account. The analysis completed by Gannett Fleming, to assess the impact of reflecting the full extent of the GER balance in the determination of the recommended net salvage percentages, resulted in net salvage percentages that are considered abnormally high. A summary of that analysis is shown on page VIII-42. This indicates that further analysis of the GER account is warranted. Therefore, while the GER costs were reviewed during this study, they were not fully factored into the net salvage estimates at this time. When and to what extent the GER costs are included in the net salvage estimates of a future depreciation study, the expectation is that net salvage percentages will be higher (i.e., higher negative net salvage percentages) and this will increase depreciation rates, all else being equal.*
>
> [emphasis added]

a) Has Maritime Electric conducted any additional analysis of the GER account?
b) Please provide the analysis (if conducted) and include any results of the analysis.
c) Will the results of this analysis impact depreciation rates?

Response:

a. Additional analysis of the general expense retirement ("GER") account has not yet been completed.
b. See response to question a.
c. While the additional analysis has not yet been completed, it is anticipated that retirement costs will only increase in the future as the amount of the system network infrastructure is replaced over the next several years.

MARITIME ELECTRIC
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All our energy.
All the time.

INTERROGATORIES

IR-3 – Attachment 1

Maritime Electric Company, Limited
Schedule of Rates

Rate Code		March 1, 2022	March 1, 2023	March 1, 2024	March 1, 2025
110	**Residential**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1592	$ 0.1652	$ 0.1715
	Energy Charge per kWh for balance kWh	$ 0.1228	$ 0.1265	$ 0.1313	$ 0.1362
130	**Residential Rural**				
	Service Charge	$ 26.92	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1592	$ 0.1652	$ 0.1715
	Energy Charge per kWh for balance kWh	$ 0.1228	$ 0.1265	$ 0.1313	$ 0.1362
131	**Residential Seasonal**				
	Service Charge	$ 26.92	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1592	$ 0.1652	$ 0.1715
	Energy Charge per kWh for balance of kWh	$ 0.1228	$ 0.1265	$ 0.1313	$ 0.1362
133	**Residential Seasonal Option**				
	Service Charge	$ 37.50	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1592	$ 0.1652	$ 0.1715
	Energy Charge per kWh for balance of kWh	$ 0.1228	$ 0.1265	$ 0.1313	$ 0.1362
232	**General Service**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1871	$ 0.1956	$ 0.2030	$ 0.2107
	Energy Charge per kWh for balance of kWh	$ 0.1241	$ 0.1279	$ 0.1328	$ 0.1377
233	**General Service - Seasonal Operators Option**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1871	$ 0.1956	$ 0.2030	$ 0.2107
	Energy Charge per kWh for balance of kWh	$ 0.1241	$ 0.1279	$ 0.1328	$ 0.1377
320	**Small Industrial**				
	Demand Charge - per kW	$ 7.46	$ 7.46	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1834	$ 0.1916	$ 0.1988	$ 0.2064
	Energy Charge per kWh for balance of kWh	$ 0.0950	$ 0.0967	$ 0.1004	$ 0.1040
310	**Large Industrial**				
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0780	$ 0.0808	$ 0.0837	$ 0.0867
340	**Long Term Contract** (Currently no customers in this rate category)				
	Demand Charge per kW	$ 15.51	$ 15.51	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.1044	$ 0.1067	$ 0.1108	$ 0.1149
330	**Short Term Contract** (Currently no customers in this rate category)				
	Demand Charge - per kW	$ 16.79	$ 16.79	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.1036	$ 0.1057	$ 0.1098	$ 0.1138
	Energy Charge per kWh for balance of kWh in the month	$ 0.0869	$ 0.0878	$ 0.0912	$ 0.0945

INTERROGATORIES

IR-28 – Attachment 1

2022 RISK AND INSURANCE MANAGEMENT REPORT

September 2022

EXECUTIVE SUMMARY

Fortis Inc. manages and administers a group insurance program that covers all of Fortis Inc.'s holdings and subsidiaries' assets with certain exceptions for CH Energy Group, Inc., UNS Energy Corporation, ITC Holdings Corp. and various smaller, locally placed lines of coverage. Experience has shown that such participation is materially beneficial to all participants. Through the pooling of geographically diversified risks, the consolidated portfolio provides access to the larger markets specializing in electric and gas utility class risks, broader coverages at more favourable terms, leverage and purchasing power and reduced broker fees and insurance program administration costs, than would be realized by any one of the participants on a stand-alone basis. All policies of insurance were successfully renewed effective July 1, 2022.

The 2022-2023 general insurance renewal was once again challenging; however, market conditions have improved significantly compared to 2018-2021. Losses continue to grow in frequency and severity due to machinery breakdown claims, natural catastrophic weather events and social inflation. Rate increases are still common across most coverage lines of general insurance; however, the rate of increases have tempered. Although many insurers have maintained a focus on underwriting scrutiny and risk appetite, new and increased capacity has started to enter the marketplace, resulting in a favourable impact on rating. In addition, Covid-19 losses have not materialized as expected. Furthermore, insurers are seeking new income to offset premium losses due to corporate ESG positions and guidelines. Increases in capital deployment in subsequent years should continue to offset and potentially reduce premium rates going forward. Coverage restrictions are likely to continue despite new capacity and reduced rate increases, particularly with respect to Cyber perils for traditional lines of coverage. In addition, insurer-imposed retention increases are still commonplace, particularly across Cyber Liability and Management Liability policies and coverages.

The 2022-2023 placement was largely negotiated with incumbent markets; however, a number of new insurers are participating on the program in order to maintain adequate levels of insurance and optimize pricing. Overall, the general insurance market is significantly more stable in terms of Property, Directors and Officers and Canadian Excess Casualty rates and premiums compared to 2021.

Despite the trend toward favourable market conditions, the specialty Power Property markets remains selective and disciplined in underwriting risks with natural catastrophe exposures, which apply to Maritime Electric in varying degrees. Although Fortis maintains a wide geographic spread of insured assets, flood and machinery breakdown exposure on the East coast continues to be the focus of the underwriting markets with respect to Maritime Electric. However, maintaining updated modelling, risk reports, surveys and loss analysis for Maritime Electric throughout the pandemic have assisted in quantifying various catastrophic loss scenarios as well as alleviating some of the uncertainties associated with the underwriting and modeling process. These reports, coupled with various risk and operational improvements, have resulted in maintaining underwriting terms and conditions that properly address these exposures.

Maritime Electric’s total insurance costs for the July 1, 2022 renewal period increased by 5.5% to $1,185,280 compared to 2021. This increase is mostly due to premium increases across most lines of coverage, inflationary factors, increases in exposure units and an increase in foreign exchange. It should be noted that the premium rate increases are the result of market conditions and not a reflection of Maritime Electric or Fortis Inc.’s risk profile. Five-year loss ratios across all lines of coverage remain favourable. Table 1 summarizes Maritime Electric’s insurance cost for the renewal period July 1, 2018 – July 1, 2023.

TABLE 1 – INSURANCE COSTS BY POLICY TYPE

Policy	2022 Premium	2021 Premium	Variance	Variance (%)	2020 Premium	2019 Premium	2018 Premium
PROPERTY							
Property (incl. B&M)	$985,191	$929,219	$55,972	6.0	$829,227	$641,685	$629,315
Terrorism	3,470	3,205	265	8.3	3,048	3,276	-
	988,661	**932,424**	**56,237**	**6.0**	**832,275**	**644,961**	**629,315**
CASUALTY							
General Liability	43,599	41,688	1,911	4.6	39,691	37,552	41,930
Umbrella / Excess Liability	56,980	60,776	-3,796	-6.2	35,869	28,979	26,086
Automobile	25,508	23,239	2,269	9.8	20,963	20,698	19,361
Non-Owned Aviation	0	70	-70	-100.0	241	0	76
Owned Aviation (UAV)	2,403	1,937	466	24.1	2,941	2,239	2,323
	128,490	**127,710**	**780**	**0.6**	**99,705**	**89,468**	**89,776**
MANAGEMENT LIABILITY							
Directors & Officers	6,973	7,567	-594	-7.8	5,488	5,161	5,247
Fiduciary	78	80	-2	-2.5	72	50	55
Comprehensive Crime	2,196	1,876	320	17.0	1,927	1,569	1,693
Employment Practices Liability	2,323	2,109	214	10.1	1,694	1,608	1,480
	11,570	**11,632**	**-62**	-0.5	**9,181**	**8,388**	**8,475**
SPECIAL PURPOSE / MISC							
Cyber / Privacy Liability	20,294	13,662	6,632	48.5	10,725	10,071	9,584
Contingent Protection	287	287	0	0.0	287	311	311
Broker Service Fee	35,978	37,417	-1,439	-3.8	37,690	44,383	43,562
	56,559	**51,366**	**5,193**	10.1	**48,702**	**54,765**	**53,457**
TOTAL	**1,185,280**	**1,123,132**	**62,148**	**5.5**	**989,863**	**797,582**	**781,023**

NOTE: Excludes taxes, where applicable; All premiums and fees presented in Canadian dollars. For report comparison purposes, all premiums invoiced in USD were converted to CAD using the exchange rates of 1.2886 and 1.2394 as of July 1, 2022 and July 1, 2021, respectively.

Appendix A provides further details regarding coverages and premiums.

Appendix B provides a summary of the various insurance policies that describes what is insured by each policy and the related coverage limits and deductibles.

Appendix C details the insurance carriers for all lines of coverage.

Appendix D provides a letter from the broker confirming the appropriateness of the insurance coverages maintained by Fortis and Maritime Electric.

APPENDIX A – DETAILS OF INSURANCE COVERAGES AND PREMIUMS

INSURANCE PROGRAM DETAILS

PROPERTY INSURANCE PROGRAM

Multiple quarters of improved underwriting results continue to temper property rate increases, suggesting that the power property sector is nearing rate adequacy. The stabilizing of property rate increases coincides with a stabilization and increase in insurance capacity, mostly due to years of increased pricing and tightening of coverage terms and conditions. For 2022, insurers are seeking relatively small premium rate increases in the vicinity of 5% - 7% for accounts with favourable loss ratios. However, challenges related to new technology and the cost to replace complex equipment, a changing workplace and the replacement of experienced operators and climate-related losses have all increased the average cost of claims across the industry. Equipment breakdown claims account for the majority of power property losses and despite a decrease in loss frequency, the average machinery breakdown claim has increased from USD $34M in 2019 to USD $44M in 2021. Insured losses from Hurricane Ida were approximately $36B resulting in the third costliest hurricane on record for insurers while insured losses from winter weather reached a record high of $17B in 2021.

Despite these trends, insurance capacity on the North American Property placement increased in 2022 such that higher priced capacity could be reduced, thus lowering overall premium. At present, property insurance represents approximately 83% of the total premium spend for Maritime Electric. Property rates increased by an average of 3.7% on the North American program while insured values for Maritime Electric increased by 3.4% to $640 million. Overall program structure changed slightly in terms of carriers and includes various domestic and London insurers who participate on a subscription basis as per Table A1. It is important to note that transmission and distribution line assets continue to be excluded from coverage as coverage for these are either unavailable or uneconomical. However, transmission and distribution lines within 1,000 feet of insured generation plants or substations, as well as Maritime Electric’s submarine cables, are fully insured.

Overall, Maritime Electric’s property premium increased by 6.0% to $985,191 in 2022 due to a 2.6% allocated premium rate increase coupled with the 3.4% increase in insured values.

TABLE A1 – NORTH AMERICAN PROPERTY PROGRAM

Insurer	Primary $100M (%)	Excess $550M (%)
Swiss Re (Westport)	16.0	16.0
AIG	12.0	12.0
AEGIS	10.875	5.125
Royal SunAlliance	9.0	9.0
Allianz	8.0	8.0
AXA XL	7.0	7.0
Berkshire Hathaway	6.50	6.5
BI & I	10.0	---
Economical	3.0	3.0
Northbridge	1.75	---
Argenta/Helvetica/ACT/EIM	15.875	---
Liberty	---	7.5
Temple	---	10.0
Zurich/SSRU/RSA	---	15.875
London Cat Wrap	---	---
FM Global	---	---
TOTAL	**100**	**100**

With the exception of UNS Energy, all Fortis Property policies continue to provide little to no coverage for acts of terrorism. Due to these exclusions, coverage is purchased through a separate Terrorism Property insurance policy. The policy covers all physical assets on a full replacement cost basis including Business Interruption up to the policy limit of $100M as well as a sublimit of $20M for Cyber Terrorism. The terrorism property insurance market has not experienced the same degree of rate increases compared to the general property market over the last number of years, however premium rate increased by 6.5% compared to 2021 resulting in an 8.3% increase in premium when coupled with the increase in insured values and foreign exchange.

CASUALTY INSURANCE PROGRAM

General Liability and Excess Liability

The general liability insurance market is yielding average rate increases in the vicinity of 5% compared to 2021. While most accounts are experiencing the rate increases referenced above, Fortis Inc. has maintained a strong loss ratio under the Commercial General Liability program over the last ten years which resulted in a 3.3% premium rate increase compared to 2021. Maritime Electric's allocated premium increased by 4.6% to $43,599 compared to 2021.

The excess liability market for Canadian domiciled risk remains challenging due to years of flat or reduced premium rate renewals coupled with wildfire exposure in Western Canada. However, an increase in insurer capacity in 2022 resulted in a favourable impact on program premium. During the 2021 renewal, expiring capacity provided by some insurers was reduced compared to the expiring term resulting in replacement capacity being secured at additional premium. However, the opposite occurred in 2022 such that a 37% premium decrease was achieved in the first excess layer due to a new insurer participating on the program. Maritime Electric's allocated premium for the Umbrella and Excess policies decreased by 6.2% to $56,980 compared to $60,776 in 2021.

Maritime Electric continues to purchase $150 million of general and excess liability insurance on a combined basis with the Canadian and Caribbean subsidiaries via domestic insurance companies in Canada. The program at present consists of ten layers of liability insurance provided by twelve different insurance carriers. On a combined basis, premium has decreased by 1.8% compared to the prior term due to the factors detailed above despite and increase foreign exchange on the 8th excess layer. It is uncertain if this pricing trend will continue in subsequent renewal periods and will largely depend upon inflation and casualty claim trends. Premium allocations are based on a formal, exposure-based model and Figure A1 below depicts the program structure and limits.

Figure A1 – Maritime Electric Casualty Insurance Program

Layer 4 USD $50M	8th Excess Liability - USD $50M
Layer 3 CAD $95M	7th Excess Liability - CAD$20M 6th Excess Liability - CAD $5M 5th Excess Liability - CAD $10M 4th Excess Liability - CAD $10M 3rd Excess Liability - CAD $10M 2nd Excess Liability - CAD $15M 1st Excess Liability - CAD $10M Umbrella Liability - CAD $15M
Layer 2 CAD $5M	Commercial General Liability - CAD $5M
Layer 1 Retention	Retentions CAD $200K (FAB) CAD $100K (FBCH) CAD $25K (all other entities)

Automobile Liability

Fortis maintains a combined Automobile Liability policy covering all licensed vehicles owned or leased by Fortis Inc., Newfoundland Power, Maritime Electric, FortisOntario and FortisAlberta.

The combined policy was renewed with QBE Canada with a 5.0% increase in average rate. Terms and conditions are the same as the expiring policy. Maritime Electric's allocated premium increased by 9.8% from $23,239 in 2021-2022 to $25,508 in 2022-2023.

Non-Owned Aircraft Liability

Fortis maintains a Non-Owned Aircraft Liability policy to cover third party liabilities which may arise out of the operation of fixed and rotary winged aircraft that are chartered by any of the Fortis companies. The limit is excess to the primary liability limits maintained by the various aircraft operators under contract. Effective July 1, 2022, the policy was renewed with Global Aerospace at the same terms and conditions as the expiring policy. Overall policy premium remained unchanged from the prior term. For 2022-2023, no premium was allocated to Maritime Electric as no flying hours were reported.

MANAGEMENT LIABILITY INSURANCE PROGRAM

Directors and Officers Liability

The Directors and Officers Liability insurance program provides $250M of coverage designed to protect the personal liabilities of the directors and officers of Fortis Inc. and its subsidiary companies. In addition, the policy provides coverage for the entities for defence and settlement of securities claims. In 2021, the marketplace for dual listed, public-traded companies was characterized by insurers reducing capacity and applying steep premium rate increases. Similar to the excess casualty market, replacement capacity was difficult to source and was being procured at premium rates much higher than the expiring capacity. Insurers were experiencing loss ratios exceeding 100% and eighteen consecutive quarters (Q1 2014 to Q2 2017) of average rate decreases as the reason behind reduced capacity and increased rates. In addition, a trend emerged whereby D&O policies were being triggered by "event-driven litigation" (i.e. incidents that primarily trigger other lines of insurance but contain an allegation or claim against an individual director or officer). This resulted in a year-over-year premium increase of 50% in 2021-2022. Although these claims trends remain active for 2022, insurer capacity has stabilized significantly compared to 2021. This suggests that D&O insurers have achieved rate adequacy which has had a favourable impact on program premium. Furthermore, the primary policy with Berkshire Hathaway contains a rate guarantee that limits the year-over-year rate increase to a maximum of 10% contingent on claims experience, market cap and M&A activity.

Due to the stabilization of insurer capacity, the policy structure, coverage and retentions remain unchanged in 2022-2023. Program premium has decreased by 6.6% to $2,256,580 due to rate decreases in the middle layers of the program, which were the same layers that experienced the largest increases in 2021. The premium for the first $95 million of coverage (Primary – 5th Excess) is allocated 50% to Fortis Inc. with the balance allocated to the subsidiaries based on their percentage of Identifiable Assets as of year-end 2021. Premium for all layers above $95 million is allocated 100% to Fortis Inc. As a result, Maritime Electric's allocated premium decreased by 7.8% to $6,973 in 2022-2023.

TABLE A2 – DIRECTORS AND OFFICERS LIABILITY PROGRAM

Coverage / Layer	Limit of Liability (CAD)	Carrier	Premium (CAD)[1]
Primary D&O	15,000,000	Berkshire Hathaway	390,000
1st Excess D&O	35,000,000	AEGIS	343,890
2nd Excess D&O	15,000,000	AIG	119,940
3rd Excess D&O	10,000,000	Everest	119,000
4th Excess D&O	10,000,000	Aviva	92,000
5th Excess D&O	10,000,000	GAIG	87,500
6th Excess D&O	50,000,000	AXA/CNA/Axis/Starr/Swiss Re	437,500
7th Excess D&O	35,000,000	Lloyds	239,400
8th Excess D&O	10,000,000	Arch	55,000
9th Excess D&O (Side A DIC)	10,000,000	Hartford	54,000
10th Excess D&O (Side A DIC)	25,000,000	Berkley	173,750
11th Excess D&O (Side A DIC)	15,000,000	Chubb	93,300
12th Excess D&O (Side A DIC)	10,000,000	Zurich	51,300
TOTAL	**250,000,000**		**2,256,580**

NOTE: - Excludes taxes and fees where applicable
- 1st Excess AEGIS includes a membership credit of $68,110 for 2022.

Fiduciary Liability

The Fiduciary Liability policy, which provides liability protection for acts, errors or omissions arising from the administration of employee pension and benefit plans, consists of a primary CAD $10,000,000 policy insured with Berkshire Hathaway as well as three Excess Fiduciary Liability policies for CAD $10,000,000 insured with Travelers, CAD $10,000,000 insured with CNA and CAD $5,000,000 insured with Markel. "Excessive Fee" claims continue to erode underwriting results, particularly in the United States. Excessive fee claims are claims against fiduciaries alleging that the fees charged by outside plan administrators are substantially higher than the average fee. Insurers continue to either significantly increase retentions for these types of claims or exclude coverage outright. Although excessive fee claims remain insured under the Fortis program subject to a $250,000 retention for non-US plans, retention increases in subsequent years is anticipated. In addition, excessive fee claims may become an uninsurable exposure in future program renewals, if losses continue to escalate. All other limits, terms and conditions are unchanged from the prior term. Premium on the group policy increased by 9.3% in 2022 with Maritime Electric's allocated premium decreasing by 2.5%.

Comprehensive Crime

A Comprehensive Crime policy, which provides coverage for losses of money and securities arising from employee dishonesty, burglary, forgery, etc. is maintained for the Fortis Group of Companies. Total policy premium increased by 18.2% from $116,193 to $137,300 due to 13% increase in rate, market conditions, an increase in foreign exchange and an insured loss that was settled in Q2 2021 for an employee dishonesty incident that occurred in 2019. Premium is allocated to the participating subsidiaries based on the number of employees that fall within insurer-defined categories. Maritime Electric's allocated premium increased by 17.0% to $2,196 in 2022-2023.

Employment Practices Liability

Employment Practices Liability insurance provides liability insurance against wrongful acts arising from the employment process such as wrongful termination, sexual harassment, discrimination, retaliation, etc. The policy provides total liability limits of USD $15M via a primary USD $10M policy with Chubb followed by a USD $5M policy with Berkshire Hathaway. Policy retentions remain unchanged from the prior year at USD $250,000 for all Canadian and Caribbean subsidiaries. The annual premium, excluding taxes, fees, etc. increased by 8.4%, due to a 5% increase in rate and increase in foreign exchange. Policy premium allocation is based on the underwriters rating of risk with 67% of the total premium allocated to the US subsidiaries and 33% of the premium allocated to the Canadian and Caribbean subsidiaries. Of this 33%, 50% is allocated to Fortis Inc. with the remainder allocated to the Canadian and Caribbean subsidiaries based on total number of employees. As such, Maritime Electric's allocated premium increased by 10.1 to $2,323 over the prior term.

SPECIAL PURPOSE / MISCELLANEOUS COVERAGES

Cyber and Network Security Liability

The Group Cyber and Network Security Liability policy changed significantly in 2022 due to a change in carrier and increase in policy limits and retentions. Effective July 1, 2022, AEGIS succeeded Liberty/Kiln as the Cyber Liability insurer for Fortis Inc. AEGIS is a well established and financially secure energy and utility mutual that specialize in offering insurance services to the power and energy sector. AEGIS currently participates on the North American Property, Excess Casualty and Directors and Officers program for Fortis Inc. The Cyber liability insurance market has continued to deteriorate due to a high frequency of claims in the general cyber market, resulting in insurance capacity becoming increasingly restricted and difficult to procure. In addition, industry benchmarking data suggested that the expiring USD $25M limit was falling short of industry standards. The change in insurers resulted in an increase in available limit such that Fortis Inc. now procures USD $50M of coverage with no material changes in coverage terms. Retentions have increased to USD $2.5M for all claims. The policy continues to offer protection against certain first and third party exposures such as the failure to protect the personal information of clients/customers as well as the violation of the security of computer systems and ransomware up to the policy limit of USD $50M. All other coverages and terms remain consistent with the expiring policy, however coverage restrictions on subsequent renewals, particularly those related to ransomware and business interruption, are anticipated. Overall program premium has increased by 49.3% from CAD $949,018 in 2021-2022 to CAD $1,417,460 due to a 100% increase in limit and increase in foreign currency exchange. Similarly, Maritime Electric’s allocated premium increased by 48.5% from $13,662 in 2021 – 2022 to $20,294 in 2022-2023. Fortis Inc. will continue to work with AEGIS on subsequent renewals to lower the retention applicable to Maritime Electric for this line of coverage.

Brokerage Agreement

Fortis exercised an extension option with Aon Reed Stenhouse, Inc. in April of 2021 reappointing them as Fortis' Property and Casualty insurance broker for a further two-year term effective July 1, 2021. As per the previous term, the service fee allocation for 2022-2023 is based on each company's percentage of the total net premiums for the year prior (i.e. July 1, 2021 – July 1, 2022) which expedites the issuance of the service fee invoices. CH Energy Group, UNS Energy and ITC Holdings Corp. remain on a flat service fee negotiated with Aon Reed Stenhouse. The total service fee decreased by 3.5% to $1,493,224 due to a credit applied in 2022-2023 related to the exceedance of a commission cap in 2021. Maritime Electric’s allocated brokerage and placement fee decreased by 3.8% from $37,417 to $35,978 compared to the prior term.

Risk Management

The existing program continues to meet the insurance needs of the Corporation and its subsidiaries, remaining consistent with the insurance programs of other North American electrical and gas utilities.

APPENDIX B – SUMMARY OF INSURANCE

2022 - 2023 INSURANCE PROGRAM

CATEGORY OF INSURED RISK	FORM OF INSURANCE	MAXIMUM LIMIT PER OCCURRENCE	RETENTION PER OCCURRENCE	COVERAGE DESCRIPTION
PROPERTY	North American Property – combined All Risk and B&M	$500,000,000 To $650,000,000	$250,000 - $1,000,000	Covers all real and personal property against All Risks of direct physical loss or damage including boiler explosion and machinery breakdown. Electric utility T&D assets covered within 1,000' of generating station or substation; plus submarine cables. FBCH's T&D assets fully insured + B.I. coverage.
	UNS Property	USD $2,400,000,000	USD $100,000 - $3,500,000	Covers all real and personal property against All Risks of direct physical loss or damage including boiler explosion and machinery breakdown excluding T&D lines
	Property - Terrorism	$100,000,000	$100,000	Covers property damage and resulting business interruption arising from acts of terrorism/sabotage/riots/strikes/etc.
	Caribbean Property – combined All Risk and B&M	USD $100,000,000 Except $150,000,000 excess limit for CUC for non-cat. losses	BECOL USD $250,000 - $2,000,000 CUC USD $1,000,000 - $4,000,000 FTCI USD $750,000 - $2,000,000	Covers all real and personal property against All Risks of direct physical loss or damage including boiler explosion and machinery breakdown, and B.I. T&D assets covered within 1,000' of generating station or substation.
CASUALTY	Commercial General Liability (Canada/Caribbean)	$5,000,000 with a $25,000,000 Ann. Aggr.	$25,000 - $200,000	Covers the legal liability to third parties for Bodily/Personal Injury and Property Damage, resulting from the companies' operations
	Umbrella (Primary & Excess layers)	$145,000,000 except $485,000,000 for FAB, FBC, FBCH, $190,000,000 for UNS/CH/ITC	That of underlying policies or $10,000	Covers legal liability on a follow form basis, which is in excess of the coverage provided on underlying CGL, Auto and Non-Owned Aircraft policies.
	Excess Liability (US)	USD $150,000,000	USD $500,000 - $2,000,000	Covers the legal liability to third parties for Bodily/Personal Injury and Property Damage, resulting from the companies' operations
	Automobile (Canada except BC)	USD $2,000,000	Nil	Blanket fleet policy covering all vehicles owned, leased to or operated by all companies except in BC, including ATVs, Snowmobiles, Argos and Go-Tracks. No 1st party PD coverage.
	Automobile (ITC)	USD $1,000,000	USD $250,000	Blanket fleet policy covering all vehicles owned, leased to or operated by ITC including ATVs, Snowmobiles, Argos and Go-Tracks. No 1st party PD coverage.
	Non-Owned Aircraft	$10,000,000	Nil	Covers the legal liability to third parties for Bodily/Personal Injury and Property Damage resulting from the companies' chartering of fixed / rotary wing aircraft.
MANAGEMENT LIABILITY	Directors & Officers	$250,000,000	$500,000 Corp. Indem. / $2,000,000 Securities claims	Covers against claims brought against the Company and its Directors and Officers. Includes $50M of Excess Side A Coverage.
	Fiduciary Liability	$35,000,000	$100,000 - $2,500,000	Covers liabilities arising out of the administration of pension plans and other employee benefit plans.
	Comprehensive Crime	USD $10,000,000	USD $250,000	Covers loss arising from employee dishonesty/burglary/forgery
	Employment Practices Liability	USD$15,000,000	USD $250,000; Except: UNS/CH/ITC: USD$500,000	Covers wrongful acts arising from the employment process.
SPECIAL PURPOSE / MISCELLANEOUS	Cyber / Privacy Liability	USD $50,000,000	USD $2,500,000	Covers loss arising out of failure to protect personal information of clients, customers & employees.
	Worker's Compensation (U.S)	Statutory Limits	USD $500,000 - $750,000	Covers wage replacement and medical benefits to employees injured in the course of employment.

APPENDIX C – INSURANCE MARKETS

APPENDIX C – INSURANCE MARKETS

Insurance Markets 2022-2023		
Coverage	**Limit**	**Insurance Markets**
Property (All Risk, Including B&M)	Primary ($100M)	Swiss Re (Westport) (16%)
		AIG (12%)
		Associated Electric & Gas Services Limited (AEGIS) (10.875%)
		Royal & Sun Alliance Insurance Company (9%)
		Allianz Global Risks US Insurance Company (8%)
		AXA XL Catlin (7%)
		Berkshire Hathaway Specialty Insurance (6.5%)
		BI&I (10%)
		Economical (3%)
		Northbridge (1.75%)
		Lloyd's Syndicate ARG (15.875%)
	Excess ($550M)	Swiss Re (Westport) (16%)
		AIG (12%)
		Associated Electric & Gas Services Limited (AEGIS) (5.125%)
		Royal & Sun Alliance Insurance Company (9%)
		Liberty Mutual (7.5%)
		Allianz Global Risks US Insurance Company (8%)
		AXA XL Catlin (7.0%)
		Economical (3%)
		Temple (10%)
		Lloyd's Syndicate ARG (15.875%)
Commercial General Liability	$5M	QBE Services Inc. (100%)
Umbrella Liability (Primary – 8th Excess)	Primary - $15M	AIG Insurance Company of Canada (100%)
	1st Excess - $10M	Volante (100%)
	2nd Excess - $15M	Arch Canada
	3rd Excess - $10M	Starr Insurance & Reinsurance Limited (100%)
	4th Excess - $10M	Volante (100%)
	5th Excess – $10M	AIG Canada (100%)
	6th Excess – $5M	Liberty Mutual (100%)
	7th Excess - $20M	Northbridge (100%)
	8th Excess – USD $50M	Quota Share: (Allianz, HDI, SSRU) – 100%
Automobile	$2M	Lloyds (QBE & Kiln) (100%)
Non Owned Aircraft	$10M	Global Aerospace (100%)
Directors & Officers Liability	Primary – $15M	Berkshire Hathaway Specialty Insurance (100%)
	1st Excess - $35M	Associated Electric & Gas Services Limited (AEGIS) (100%)
	2nd Excess - $15M	AIG Insurance Company of Canada (100%)
	3rd Excess - $10M	Everest Insurance Company (100%)
	4th Excess - $10M	Aviva (100%)
	5th Excess - $10M	GAIG (100%)
	6th Excess - $50M	Quota Share (AXA XL, CNA, AXIS, Starr) (100%)
	7th Excess - $35M	Lloyd's of London Underwriters (100%)
	8th Excess - $10M	ARCH Insurance Canada Ltd. (100%)
	9th Excess - $10M	Hartford Fire Insurance Company (100%)
	10th Excess - $25M (Lead DIC)	Berkley Professional Liability Company (100%)
	11th Excess - $15M (Excess DIC)	Chubb Insurance Company of Canada (100%)
	12th Excess - $10M (Excess DIC)	Zurich Insurance Company Ltd. (100%)
Employment Practices	Primary – $10M (USD)	Chubb Insurance Company of Canada (100%)
	1st Excess - $5M (USD)	Berkshire Hathaway Specialty Insurance (100%)
Fiduciary Liability	Primary - $10M	Berkshire Hathaway Specialty Insurance (100%)
	1st Excess - $10M	Travelers Insurance Company of Canada (100%)
	2nd Excess - $10M	CNA Insurance Company of Canada (100%)
	3rd Excess - $5M	Markel (100%)
Comprehensive Crime	$10M (USD)	AIG Insurance Company of Canada (100%)
Cyber / Privacy Liability	$50M (USD)	Associated Electric & Gas Services Limited (AEGIS) (100%)

APPENDIX D – BROKER LETTER

July 4th, 2022

Maritime Electric Co. Ltd.
PO Box 1328
180 Kent Street
Charlottetown, PE   C1A 7N2

Attention: Michelle Francis

Dear Ms. Francis:

In compliance with your request, Aon Reed Stenhouse Inc. ("Aon") confirms the appropriateness of coverage afforded by your company's property and casualty insurance programs, considering the availability and cost of coverage in the present insurance market. Globally, Aon provides insurance brokerage services to numerous major utilities and property risks. Our experience with these risks enables us to confirm that the coverage and limits provided by your insurance program are consistent in scope and nature with similar types of risks worldwide.

Based on Aon's intensive marketing of your insurance programs, we can confirm that the rates and coverage for the 2022-2023 term are the best available given the current market conditions.

We trust the foregoing provides the information you require. Should you have further questions or concerns, please do not hesitate to contact the undersigned.

Yours sincerely,

Aon Reed Stenhouse Inc.

Rob Bennett, BBA, CIP, CAIB

cc. Gordon Payne

Aon Risk Solutions
125 Kelsey Drive, Suite 100 | St. John's, NL, A1B 0L2 | Canada
t +1.709.739.1000 | **f** +1.709.739.1001 | aon.ca
Aon Reed Stenhouse Inc.

I N T E R R O G A T O R I E S

IR-42 – Attachment 1

FORTIS INC.

TO: Subsidiary CFOs and Financial Planning & Analysis Teams

FROM: Julie Avery, Senior Director, Finance and Ian McKay, Financial Analyst

SUBJECT: 2022-2026 Business Plan: Preliminary Financial Assumptions & Corporate Recoveries

DATE: March 31, 2021

Below you will find preliminary financial assumptions and corporate recoveries to be used for the business plan submissions due in May.

A. Key Financial Assumptions

The assumptions provided below are meant to provide reasonable consistency across the group of companies. To the extent that the assumptions may not be appropriate for your company, please reach out to discuss.

Over the coming months we will revisit these initial assumptions to determine whether any changes are warranted based on the passage of time and new information. Any material changes to these assumptions will be communicated as the information becomes available.

All dollar amounts below are in Canadian dollars, unless otherwise indicated. U.S. and Caribbean subsidiaries should translate the dividend rates and share prices to U.S. dollars using the below-noted foreign exchange rate.

Foreign Exchange Rate

Foreign Exchange Rate		
	2021	**2022-2026**
USD:CAD	1.28	1.28

Dividend Rate

[redacted]						
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]						
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Fortis Share Price

[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Performance Share Unit ("PSU") Payout Percentage

Please assume a PSU payout percentage of 100% for all PSUs granted throughout the plan period (2022-2026).

Interest Rates

The following interest rate ranges should be used as guidance for any long-term debt issuances throughout the five-year plan period 2022-2026. It is expected that any holding company debt issuances will be on the high end of the range, whereas regulated utility debt issuances will be on the lower end of the range.

Interest Rates			
	5-Year	**10-Year**	**30-Year**
Canada	1.84% - 2.07%	2.69% - 3.06%	3.39% - 3.76%
U.S.	1.80% - 1.93%	2.80% - 3.15%	3.76% - 4.17%

B. Corporate Recoveries

Below are the preliminary corporate recoveries for the 2021 forecast and the 2022-2026 Business Plan. The allocation has been calculated using a combination of total assets excluding goodwill (75%) and controllable operating expenses (25%).

The Q1 2021 amount below will not agree to the invoice you received in March 2021. The March invoice was based on forecast information from last year's business plan and included a true-up from Q4 2020. The Q2 2021 invoice will reflect the sum of Q1 and Q2 2021 below, less the amount previously invoiced for Q1 2021.

Total Recoverable Amount ($ 000s, in local currency)				
Q1 2021	**Q2 2021**	**Q3 2021**	**Q4 2021**	**2021**
$203	$140	$131	$132	$606

Q1 2022	Q2 2022	Q3 2022	Q4 2022	2022
$263	$140	$129	$139	$671

2023	2024	2025	2026
$690	$723	$728	$758

MARITIME ELECTRIC
A FORTIS COMPANY
All our energy.
All the time.

INTERROGATORIES

IR-42 – Attachment 2

Invoice

FORTIS INC.

Invoice FTS-3051
Date 3/3/2021

Fortis Inc.
Fortis Place
5 Springdale Street - Suite 1100
St. John's NL A1B 3T2

Bill To: Maritime Electric Company, Limited
P.O. Box 1328
180 Kent Street
Charlottetown PE C1A 7N2

Q1 Recoverable Expenses 2021

Customer ID	Payment Terms
MECL	Due Upon Receipt
Description	**Ext. Price**
Q1 2021 Recoveries (1)	$230,000.00
2020 True Up (2)	$11,000.00

Q1 2021 Balance Owing (3) $241,000.00

(1) *See attached for categorized breakdown of Q1 2021 Recoveries.*
(2) *Represents the true-up required based on actual expenditures incurred in the 2020.*
(3) *Represents 2021 year-to-date recoverable expenses "Billed as Estimated" based on the 2021 - 2025 Business Plan Recoveries. On a quarterly basis, these expenses may be subject to a true-up based on actual expenses incurred during the quarter. In the event that a true-up is required, any such true-up will be applied in the subsequent quarter.*

Accts Payable

00-00000-4317-00 $156,240.00
70-00000-8615-70 $84,760.00

Kate O'Brien
10-Mar-2021

HST# 10185 2416 RT0001

Remit To:
Bank of Nova Scotia
44 King Street West
Toronto, ON
M5H 1H1

Bank Number: 002
Transit: 34033
Account: 340330116610
Swift Number: NOSCCATTXXX

Beneficiary:
Fortis Inc.
Fortis Place, Suite 1100
5 Springdale Street
St. John's, NL
A1B 3T2

Fortis Inc. Non-Consolidated Business Plan
MECL Recoveries

	YTD Q1 2021
Salaries	176
Directors' fees and costs	10
Trustees and DRIP administration	2
Consulting	2
Legal	5
Audit	4
Listing and filing	3
Annual meeting and report	5
Other fees	1
Occupancy	5
Insurance	3
Office related	6
Investor Relations	1
Communications	1
Miscellaneous	1
Travel	4
Telephone	1
Total Recoverable Amount ($CAD)	**230**
2020 True Up	**11**
Q1 2021 Balance Owing	**241**

76401

Invoice

FORTIS INC.

Invoice FTS-3100
Date 6/14/2021

Fortis Inc.
Fortis Place
5 Springdale Street - Suite 1100
St. John's NL A1B 3T2

Bill To: Maritime Electric Company, Limited
P.O. Box 1328
180 Kent Street
Charlottetown PE C1A 7N2

Q2 Recoverable Expenses 2021

Customer ID	Payment Terms
MECL	Due Upon Receipt
Description	**Ext. Price**
Q2 2021 Recoveries (1)	$343,000.00
Less Q1 2021 Billing (2)	($230,000.00)

Total $113,000.00

00-00000-4317-00 $113,000.00

(1) *See attached for categorized breakdown of Q2 2021 Recoveries.*
(2) *Represents 2021 year-to-date recoverable expenses "Billed as Estimated" based on the 2022-2026 Business Plan Recoveries. On a quarterly basis, these expenses may be subject to a true-up based on actual expenses incurred during the quarter. In the event that a true-up is required, any such true-up will be applied in the subsequent quarter.*

HST# 10185 2416 RT0001

Remit To:

Bank of Nova Scotia
44 King Street West
Toronto, ON
M5H 1H1

Bank Number: 002
Transit: 34033
Account: 340330116610
Swift Number: NOSCCATTXXX

Beneficiary:

Fortis Inc.
Fortis Place, Suite 1100
5 Springdale Street
St. John's, NL
A1B 3T2

Fortis Inc. Non-Consolidated Business Plan MECL Recoveries	
	YTD Q2 2021
Salaries	240
Directors' fees and costs	15
Trustees and DRIP administration	4
Consulting	15
Legal	3
Audit	7
Listing and filing	6
Annual meeting and report	14
Other fees	2
Occupancy	10
Insurance	8
Office related	11
Investor Relations	2
Communications	4
Miscellaneous	-
Travel	-
Telephone	2
Total Recoverable Amount ($CAD)	**343**
Less: Q1 Bill	**(230)**
Q2 2021 Balance Owing	**113**

78766

Invoice

FORTIS INC.

Invoice FTS-3166
Date 9/17/2021

Fortis Inc.
Fortis Place
5 Springdale Street - Suite 1100
St. John's NL A1B 3T2

Bill To: Maritime Electric Company, Limited
P.O. Box 1328
180 Kent Street
Charlottetown PE C1A 7N2

Customer ID	Payment Terms
MECL	Due Upon Receipt
Description	**Ext. Price**
Q3 2021 Balance Owing for Recoverable Expenses	$163,000.00

Total $163,000.00

00-00000-4317-00 161,900.00
70-00000-8615-70 1,100.00

Kate O'Brien
29-Sept-2021

HST# 10185 2416 RT0001

Remit To:

Bank of Nova Scotia
44 King Street West
Toronto, ON
M5H 1H1

Bank Number: 002
Transit: 34033
Account: 340330116610
Swift Number: NOSCCATTXXX

Beneficiary:

Fortis Inc.
Fortis Place, Suite 1100
5 Springdale Street
St. John's, NL
A1B 3T2

Fortis Inc. Recovery Billings MECL Recoveries	
	YTD **Q3 2021**
Salaries	320
Directors' fees and costs	27
Trustees and DRIP administration	6
Consulting	22
Legal	8
Audit	10
Listing and filing	7
Annual meeting and report	14
Other fees	3
Occupancy	16
Insurance	12
Office related	14
Investor Relations	4
Communications	7
Miscellaneous	-
Travel	1
Telephone	2
Total Recoverable Amount ($CAD)	**473** *(1)*
Less: Q1 Bill	**(230)**
Less: Q2 Bill	**(113)**
Add: YTD Q2 True-Up	**33** *(2)*
Q3 2021 Balance Owing	**163**

(1) Represents 2021 year-to-date recoverable expenses based on the 2022-2026 Business Plan. On a quarterly basis, these expenses may be subject to a true-up based on actual expenses incurred. In the event that a true-up is required, any such true-up will be applied in the subsequent quarter.

(2) Represents the true-up required based on actual expenditures incurred from January 1 to June 30, 2021. The true-up reflects a higher actual share price as compared to the forecast.

80774

Invoice

FORTIS INC.

Invoice FTS-3232
Date 12/2/2021

Fortis Inc.
Fortis Place
5 Springdale Street - Suite 1100
St. John's NL A1B 3T2

Bill To: Maritime Electric Company, Limited
P.O. Box 1328
180 Kent Street
Charlottetown PE C1A 7N2

Customer ID	Payment Terms
MECL	Due Upon Receipt
Description	**Ext. Price**
Q4 2021 Balance Owing for Recoverable Expenses	$100,000.00

Total $100,000.00

Accounts Payable
00-00000-4317-00 100,000.00
70-00000-8615-70 0.00

Kate O'Brien
8-Dec-2021

HST# 10185 2416 RT0001

Remit To:

Bank of Nova Scotia
44 King Street West
Toronto, ON
M5H 1H1

Bank Number: 002
Transit: 34033
Account: 340330116610
Swift Number: NOSCCATTXXX

Beneficiary:

Fortis Inc.
Fortis Place, Suite 1100
5 Springdale Street
St. John's, NL
A1B 3T2

Fortis Inc. Recovery Billings MECL Recoveries	YTD Q4 2021
Salaries	401
Directors' fees and costs	42
Trustees and DRIP administration	8
Consulting	27
Legal	11
Audit	14
Listing and filing	8
Annual meeting and report	14
Other fees	5
Occupancy	21
Insurance	16
Office related	18
Investor Relations	6
Communications	9
Miscellaneous	1
Travel	3
Telephone	2
Total Recoverable Amount ($CAD)	**606** [1]
Less: Q1 Bill	**(230)**
Less: Q2 Bill	**(113)**
Less: Q3 Bill	**(163)** [2]
Q4 2021 Balance Owing	**100**

[1] Represents 2021 year-to-date recoverable expenses based on the 2022-2026 Business Plan. On a quarterly basis, these expenses may be subject to a true-up based on actual expenses incurred. In the event that a true-up is required, any such true-up will be applied in the subsequent quarter.

[2] Included a true-up for actual expenditures incurred from January 1 to June 30, 2021. The true-up reflected a higher actual share price as compared to the forecast.