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November 24, 2020

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The Island Regulatory and Appeals Commission

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

Dear Ms. Mosher:

General Rate Application - Docket UE20944
Response to Interrogatories IR-90 to IR-96 from Commission Staff

Please find attached the Company's response to Interrogatories IR-90 to IR-96 from Commission Staff with respect to Docket UE20944 – General Rate Application and the Application submitted by the Company for electric rates effective March 1, 2020 and March 1, 2021.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

GCC18
Enclosure
cc: Nicole McKenna – Carr, Stevenson & MacKay

The Island Regulatory and Appeals Commission (the "Commission"), in assessing the application submitted by Maritime Electric Company, Limited ("Maritime Electric" or "MECL") for electric rates effective March 1, 2020 and March 1, 2021, requests responses to the following interrogatories:

IR-90 Since 2013, MECL has been collecting its annual contribution to the cable contingency fund ($375,000) through a rate rider charged to electricity customers at the rate of $0.00027/kWh. In accordance with Commission **Order UE18-05**, the Commission ordered that the cable contingency contribution be collected thought the OATT, effective August 1, 2018. As there has been no change to electric rates for distribution customers since March 1, 2018, please explain:

a. How the cable contingency fund contribution has been collected since August 1, 2018?

b. Has MECL continued to charge the rate rider of $0.00027/kWh to distribution customers since August 2018?

c. If so, please provide a complete accounting of the funds collected through the rate rider from August 1, 2018 to present.

Response:

a. Since August 1, 2018, the Company has charged the Open Access Transmission Tariff ("OATT") as approved by Commission Order UE18-05, which reflects the inclusion of the annual contribution to the Cable Contingency Fund of $375,000.

b. As a consequence of 2019 customer rates remaining unchanged from the rates charged in 2018 and the 2020 customer rate increase still pending, the Company has continued to collect the $0.00027 per kilowatt hour ("kWh") rate rider implemented on March 1, 2013, which was designed to collect an annual contribution to the Cable Contingency Fund of $300,000 from Maritime Electric distribution customers.

c. With respect to item (b) above, the Company has also continued to remit to the Prince Edward Island Energy Corporation ("PEIEC") on a monthly basis the actual amount collected from customers via the rate rider, as per Order UE16-04. Since August 1, 2018, $778,856.93 has been collected and remitted to the PEIEC. The following table provides the details of the cable contingency fund collections from customers and remittances to the PEIEC since August 1, 2018.

Summary of Amounts Collected and Remitted to the PEIEC for the Cable Contingency Fund				
Sales Period	**KWh Sales**	**Collection Rate**	**Collections**	**Remittances**
August 1 - December 31, 2018	518,500,492	$ 0.00027	$ 139,995.13	$ 108,155.27
January 1 - December 31, 2019	1,286,860,320	$ 0.00027	$ 347,452.28	$ 347,211.00
January 1 - October 31, 2020	1,079,294,516	$ 0.00027	$ 291,409.52	$ 323,490.66
TOTAL	**2,884,655,328**	**$ 0.00027**	**$ 778,856.93**	**$ 778,856.93**

If the Commission had approved the cancellation of this rate rider effective March 1, 2019 then the Company would have discontinued its historical manner of remitting the collection of the rate rider to the PEIEC. Instead, the Company would have recorded a Gross Energy Supply Cost of $375,000 in both 2019 and 2020 and paid those amounts to the PEIEC. It should be noted that the calculation of the proposed rebasing of the Energy Cost Adjustment Mechanism ("ECAM") rate in the 2019 General Rate Application included the recognition of this energy supply cost. Therefore, the recognition of this Gross Energy Supply Cost, along with the rebasing of the ECAM rate, would have corresponded to the amount collected through the OATT.

However, the Commission instead ordered that customer rates in 2019 remain unchanged from that charged in 2018 and the 2020 customer rate increase is still pending.

The consequence of this in 2019 was the recognition of OATT revenue that included $375,000 without a corresponding energy supply cost. However, the corresponding energy supply cost, through the monthly ECAM adjustment, would have been recognized with a debit to ECAM (amount to be recovered from customers) and a credit representing the payable (owing) to PEIEC. The payable to PEIEC is not necessary as the Company has already remitted $347,452 to the PEIEC in 2019 through the rate rider collections in 2019. The credit (or amount owing) should really be to the distribution customers to offset the amount collected from them through the rate rider. Therefore, the credit will be reflected in ECAM since it was considered to be an energy supply cost.

The consequence of this in 2020 is yet to be determined. However, without the rebasing of the ECAM rate in 2020, the collection of the $375,000 through the OATT will follow the same pattern as described above for 2019. Therefore, the over-collection will be returned to customers via the ECAM.

IR-91 Please provide the actual monthly energy sales (GWh) for the period from January 1, 2020 to October 31, 2020, and compare to MECL's forecast monthly sales as filed in the July 2019 update [see **Exhibit M-25**]. In the event the actual energy sales differ from the forecast in any month(s), please provide an explanation for the variance(s). Please identify any variances related directly to the COVID-19 pandemic.

Response:

IR 91 - Attachment 1 provides a comparison of 2020 year-to-date sales to the July 2019 update filed with the Commission. Overall, year-to-date actual sales were 44.3 GWh below the forecast filed in the July 2019 update. Lower GWh sales results in the recognition of overall lower revenue and overall lower energy supply cost via the ECAM.

As part of Grant Thornton's review of the Company's January Filing, they reviewed the Company's energy sales forecast and on page 12 of their report noted:

> *"MECL's approach to load forecasting is an acceptable methodology within the industry. During our review of energy sales forecast model provided by MECL we found no errors or omissions …; The inputs and assumptions within the energy sales forecast were supported; …"*

Residential Sales:
Overall, actual year-to-date Residential sales in 2020 were down 1.6 GWh compared to the forecast presented in the July 2019 update. The main reasons for this variance are:

- The proposed expansion of a large agricultural customer has been delayed resulting in a decrease in the actual residential load of 18.5 GWh. The delay was initially due to construction and production start-up delays. However, it is unclear whether the expansion was also slowed by the onset of the COVID-19 pandemic.
- This reduction was partially offset by an increase from residential non-space heating load of 13.5 GWh attributed to employees and students working from home due to COVID-19 restrictions.
- The reduction was also partially offset by a 3.4 GWh increase in residential space heating load due to an increase in heating degree days above the 10-year average.

General Service Sales:
Overall, actual year-to-date General Service sales in 2020 were down 31.3 GWh compared to the forecast presented in the July 2019 update. This decrease is assumed to be entirely attributed to the COVID-19 pandemic. Schools were closed in mid-March for the remainder of the 2019/2020 school year. All non-essential businesses were also closed for more than two months. Even as these businesses eventually reopened, travel restrictions significantly reduced tourism on the Island reducing demand for services particularly in the hospitality industry, and many businesses continue to operate with reduced capacity and/or hours due to health restrictions that remain in place.

Large Industrial Sales:
Overall, actual year-to-date Large Industrial sales in 2020 were down 6.1 GWh compared to the forecast presented in the July 2019 update. This decrease is mainly attributed to a delay in the expansion plans for a large industrial customer that was originally expected to be on-line in the fall of 2019 but was not fully operational until June 2020.

Small Industrial Sales:
Overall, actual year-to-date Small Industrial sales in 2020 were down 5.1 GWh compared to the forecast presented in the July 2019 update. This decrease is assumed to be attributed to the COVID-19 pandemic which caused the closure of all non-essential businesses for two or more months.

Street Lighting:
Overall, actual year-to-date Street Lighting sales in 2020 were down 0.3 GWh compared to the forecast presented in the July 2019 update. This decrease is mainly attributed to a faster conversion rate to LED street lighting than forecast.

IR-92 Has the COVID-19 pandemic impacted MECL's forecast financial position for 2020? If so, please explain and quantify.

Responses:

Yes, the COVID-19 pandemic has negatively impacted the Company's financial position for 2020.

Revenue is currently forecast to be approximately $4.6 million lower than that reflected in the Application for an Order Approving Changes to the Schedule of Rates Effective March 1, 2020 and March 1, 2021 ("January Filing"). The decrease is due primarily to lower General Service sales but also reflects lower sales in all customer classes. The COVID-19 pandemic is affecting sales as described in the response to IR-91.

As sales decrease so does net energy purchased. Energy supply costs are currently forecast to be approximately $3.5 million lower than that reflected in the January Filing.

The resulting forecast reduction in marginal net revenue of approximately $1.1 million, along with increased costs associated with adopting COVID-19 protection protocols, is expected to be partially mitigated by the Company's efforts to reduce operating expenses. The Company has: (i) delayed the replacement of certain retiring employees; (ii) delayed tree trimming activities; (iii) delayed certain line maintenance activities; (iv) reduced some administrative costs; (v) delayed some annual property maintenance activities; and (vi) realized lower short-debt borrowing costs as the COVID-19 pandemic has resulted in lower interest rates. It should be noted that a significant weather event or other unplanned costs before the end of the year could negatively impact these cost mitigation activities.

IR-93 In July 2019, MECL forecast its 2019 energy sales to be 1,305.5 GWh [see **Exhibit M-25**]. Its actual energy sales for 2019 were 1,286.9 GWh. Although MECL's actual energy sales were less than forecast in 2019, the Company over-earned by $3.5 million in 2019.

a. Please explain why MECL over-earned in 2019, notwithstanding that its energy sales were less than forecast, and notwithstanding that there has been no change in electric rates since March 1, 2018.

b. In the event the Company's 2019 over-earnings were due to variances between forecast and actual results or expenditures for 2019, please provide a side-by-side comparison of the forecast versus actual amounts, together with explanations for the variances.

Response:

a. The Company's regulated earnings in 2019 were $14.3 million, being the maximum allowed to achieve the rate of return on equity ("ROE") of 9.35 per cent as approved in Order UE19-08. The Company did record a Rate of Return Adjustment ("RORA") of $3.5 million in 2019 as a result of an over-collection of revenue from customers. This RORA was required even though the Commission did not approve the rate increase proposed in July of 2019 for the reasons discussed below.

The rate increase proposed in July 2019 was based on a revenue requirement designed to recover a proposed ECAM base rate and specific 2019 depreciation rates. In Order UE19-08, the Commission did not approve the proposed adjustments to the ECAM base rate or the 2019 depreciation rates. This coupled with higher-than-forecast OATT revenue (net of expenses), lower-than-forecast other expenses and adjustments to the Weather Normalization Reserve Adjustment ("WNRA") resulted in the required RORA for 2019, as noted in the table below.

Summary Table Comparison of July 2019 GRA Update Forecast to 2019 Actual	
Gross Operating Revenue	$ (1,077,768)
Net Energy Costs	2,686,199
Distribution and Transmission	(8,026)
Transmission - OATT	(382,015)
Corporate	296,545
Amortization	2,544,112
Financing Costs	(127,094)
WNRA	(430,777)
Corporate Taxes	2,264
ROE	5,681
RORA Adjustment	**$ 3,509,122**

b. A side-by-side comparison of the forecast versus actual amounts, together with further explanations for the variances is provided in IR-93 - Attachment 1 July 2019 Forecast vs 2019 Actual.

IR-94 In its report dated October 14, 2020, Grant Thornton recommends that the Commission consider "*whether the short term borrowing rate is an appropriate rate to be charged given that RORA is a component of rate base where its components earn (or pay) a return based on the Company's weighted average cost of capital (or return on average rate base)*" [see **Grant Thornton Report at page 62, lines 8-10**]. Please comment on this recommendation.

Response:

The Company has accrued interest at its short-term borrowing rate since RORA was first introduced in 2011 as per Order UE11-04.

The Company considers a short-term borrowing rate reasonable as long as the RORA balance is refunded in a short time frame. For example, in the 2016 General Rate Agreement, the Company forecast a return of the pre-2016 RORA balance over the three years of the agreement (March 1, 2016 – February 28, 2019). In the January Filing before the Commission, the Company proposed a refund of the RORA balance on December 31, 2019 in one year (March 1, 2020 – February 28, 2021).

The Company's weighted average cost of capital (or return on average rate base) ("WACC") is based on the Company's long-term debt cost and ROE. The Company's long-term debt is secured by the Company's investment in capital assets which are held on a long-term basis (i.e. for periods up to 40 years). As well, the shareholder's investment in the Company is considered to be held into perpetuity. Both are much longer term and higher risk than the RORA balance.

It is also worth noting, had the Company accrued interest at its WACC instead of its short-term borrowing rate then the amount due to customers, recognized in the RORA balance, would have increased. The other side of this adjustment would have been an increase in interest expense which would have reduced the RORA realized in that year. Therefore, the net impact to the RORA balance would be nil.

IR-95 The proposed rates and rate impact as calculated by MECL assume that electric rates will be implemented effective March 1, 2020 and March 1, 2021, and that the rate setting period will end on February 28, 2022. Please provide a schedule showing the impact on the proposed rates assuming that the proposed rates are implemented effective January 1, 2021 and that the rate-setting period will end on February 28, 2022. Assume all other requests made by MECL in the application are approved as filed.

Response:

As discussed in Section 4, Revenue Shortfall, of the Grant Thornton Report on the January Filing, the delay in approving adjustments to customer rates beyond March 1, 2020, as originally filed, adds additional complexity to the Commission's ultimate decision on rates and the recovery of the 2020 annual revenue requirement.

In May 2020, the Company requested that the Commission consider a revenue shortfall deferral account to reflect the revenue lost in the interim period in order to meet its 2020 revenue requirement and the deferral be recovered through customer rates over the remaining rate setting period. At that time, the Company provided a calculation of the revenue shortfall deferral of $1,525,240 based on a September 1, 2020 rate implementation, which reflected a revenue shortfall from March 1, 2020 to August 31, 2020 and recommended that it be collected over the remaining rate setting period of eighteen months (September 1, 2020 to February 28, 2022). As stated in our response to GT-RFI-2019-93, the model can be used to calculate the proposed deferral on whatever implementation date the Commission chooses. In Section 4.4 of their report, Grant Thornton concluded:

> *"…nothing has come to our attention that the proposed revenue shortfall...appears unreasonable. We did not note any discrepancies in the calculation of the proposed revenue shortfall and the components of the revenue shortfall are internally consistent with the Company's January 2020 filing…the Company's methodology does not appear unreasonable and is comparable to the methodology used by utilities in Newfoundland and Labrador."*

Assuming the proposed rates will be implemented effective January 1, 2021, the Company recalculated the revenue shortfall for 2020 to be $2,556,928 for the March 1, 2020 to December 31, 2020 period and recommends that it be collected over the remaining rate setting period of fourteen months (January 1, 2021 to February 28, 2022). A copy of the calculation of the revised revenue shortfall deferral is provided in Attachment 1 to this response.

The customer rate increase that had been originally proposed for March 1, 2020 reflected an increase in the Company's ECAM base rate from $91.61 to $92.25 to be effective on March 1, 2020. The current Revenue Shortfall Deferral assumes that the proposed ECAM base rate of $92.25 is approved retroactively to March 1, 2020, which ensures the proper matching of energy costs with revenue from rates. The resulting forecast increase in energy costs to be charged to the Company's income statement is $753,655 for the period March 1, 2020 to December 31, 2020.

The delay in implementing rate adjustments also impacts other amounts, outside of the revenue requirement, that are being collected from or refunded to customers as set out in Sections 3 and

4 of the January Filing including Provincial Costs Recoverable and Regulatory Deferrals. Attachment 2, page 1 to 5, to this response compares the per kWh charge for the amounts originally proposed in the January Filing to the revised amounts.

Additional schedules are provided in Attachment 3:

- Page 1 provides an analysis of the revenue requirement comparing the January Filing to the current revised proposal;
- Page 2 provides the impact on the average customer comparing the January Filing to the current revised proposal;
- Page 3 provides the composition of total energy charge per kWh by rate class for the current revised proposal which can be compared to Schedule 11-4 provided in the January Filing; and
- Page 4 provides the detailed calculation of rate base and average rate base, comparing the January Filing to the current revised proposal.

IR-96 Please provide the rates and the rate impact that arise from the following scenarios.

In the first bullet of scenarios 1 and 4, the Commission asked that our responses be based on actual results from January 1, 2020 to October 1, 2020 and forecast results from November 1, 2020 to December 31, 2020. For comparability purposes, the Company has prepared responses to scenarios 2 and 3 on the same basis.

In our response to IR-95, the proposed revenue shortfall is based on an implementation date of March 1, 2020 for customer rates as well as the adjustment to the ECAM base rate. Therefore, in light of the Commission's request in IR-96 to not assume a rate increase on March 1, 2020, we consider that to also mean there is no change to the ECAM base rate on March 1, 2020 and it will remain at $0.09161 until December 31, 2020.

For each of the scenarios in IR-96, the Company assumed an ECAM base rate effective January 1, 2021 of $0.09244 to match the effective date of revised customer rates. This effectively matches the Energy Costs to be recovered from customers in 2021, Net of ECAM, to forecast Gross Energy Costs as the proposed ECAM base rate of $0.09244 is based on the proposed Energy Supply Cost by Source (Appendix 5, Schedule 5-3 of the January Filing) for 2021 and the proposed Net Purchased and Produced Energy (Appendix 5, Schedule 5-2 of the January Filing) in 2021 as outlined the table below.

Calculation of Annual ECAM Base Rate			
Description	**Reference**		**2021 Forecast**
Energy Supply by Source ($)	SCHEDULE 5-3	A	$ 138,373,900
Net Purchased and Produced Energy X 1000 (GWh converted to kWh)	SCHEDULE 5-2	B	1,496,869,680
ECAM Base Rate		C = A / B	**$ 0.09244**

The Company respectfully provides additional comments specific to the various components of each of the scenarios to assist the Commission in its assessment of each scenario.

SCENARIO 1:
Please assume as follows:

- The Commission approves a revenue shortfall account. The balance of the revenue shortfall account is equal to the amount of revenue required for MECL to meet its 2020 rate of return calculated based on rates that are currently in effect (i.e. do not assume there was a rate increase on March 1, 2020). Please include the calculation of this amount based on actual results from January 1, 2020 until October 31, 2020, and forecast results from November 1, 2020 until December 31, 2020.
- The CTGS accumulated reserve is recovered over a sixty-month period beginning January 1, 2021.
- The Hurricane Dorian costs ($3,002,900) are recovered using the 2019 RORA balance.

- MECL's share of the EE&C costs collected through the rate rider from March 1, 2019 to December 31, 2020 are remitted to PEIEC. The EE&C rate rider for the 2020/2021 collection period is reduced accordingly. Please provide all supporting calculations, including forecasts for the period from November 1, 2020 to December 31, 2020. The balance of the RORA account and WNR account are used to offset the ECAM balance. Any remaining RORA balance is refunded to ratepayers over a twelve (12) month period beginning January 1, 2021.
- The rates are implemented effective January 1, 2021 and the rate-setting period will end on February 28, 2022.
- All other requests made by MECL in the application are approved as filed.

Response:

IR-96 - Attachment 1 provides the rates and the rate impact for Scenario 1, including changes to the proposed revenue requirement for 2020 and 2021, annual cost for a typical customer in each rate class, the energy charges per kWh, and rate base and return on rate base from those proposed in our January Filing.

In addition, supporting calculations of the various balances and rate riders or refunds are provided on page 1 of Attachment 5 – Supporting Calculations of Scenarios.

The Company also offers the following additional commentary on the assumptions provided in this scenario.

- The revenue shortfall in this scenario will increase from the amount proposed in the response to IR-95 to $3,517,971.

  The increase in the revenue shortfall reflects the year-to-date actual results from January 1, 2020 to October 31, 2020 and forecast results from November 1, 2020 to December 31, 2020, which includes the impact of lower than expected sales due to the pandemic as discussed in our response to IR-91 and IR-92. This increase is partially offset by lower net energy costs as a result of not changing the ECAM base rate on March 1, 2020.

  The revenue shortfall also includes changes to the 2020 Revenue Requirement as a result of bullets 4 (recovery of EE&C Plan costs of $445,553) and 5 (offsetting the balance of the WNRA to ECAM of $1,057,328).

- Amortizing the CTGS reserve variance over 60 months starting on January 1, 2021 increases the 2021 Revenue Requirement by approximately $1.9 million which, in turn, increases the overall rate impact for customers in 2021.

- Recovering Hurricane Dorian costs using the 2019 RORA is as proposed in the January Filing and the response to IR-95.

- The current rates approved by the Commission do not include a rate rider for the PEIEC's EE&C plan. The confusion may be the result of an error in Section 7.1.2.2 of Grant Thornton's report identified in our letter to the Commission dated November 24, 2020 Application for an Order Approving Changes to the Schedule of Rates Effective March 1, 2020 and March 1, 2021 – *Comments on Grant Thornton Report.*

  Although the Company has provided its position on the EE&C funding, if the Commission were to alternatively conclude that the Company is collecting DSM costs of $573,000 in base rates, this effectively increases the Company's 2020 Revenue Requirement from that originally proposed in the January Filing by $445,553[1]. This flows through to the revenue shortfall amount calculated in the first bullet in this scenario.

  Similar treatment applied to the 2019 EE&C Plan would require a reduction to the RORA account of $415,802[2] as explained in our comments on the Grant Thornton Report.

- Applying the forecast RORA and WNRA balances on December 31, 2020 to the ECAM balance will reduce the forecast ECAM balance to nil on December 31, 2020 and there will be a forecast balance of $1,287,772 in the RORA to be refunded to customers beginning January 1, 2021 after taking into consideration the adjustments proposed in this scenario.

  In this scenario, the Company has calculated the refund rate based on the forecast December 31, 2020 RORA balance being refunded over a 12 month period effective January 1, 2021. The Company would caution that refunding the balance over 12 months could result in an over-refund of RORA as all other rate assumptions are based on a 14 month rate setting period. The Company respectfully suggests calculating the refund rate over the full 14 month rate setting period, January 1, 2021 to February 28, 2022.

  In the January Filing and in our response to IR-95, the Company has proposed amortizing the balance of the WNRA on December 31, 2019 against the 2020 revenue requirement thereby reducing the revenue required to be collected from customers through basic rates. Applying the WNRA balance to ECAM as proposed in this scenario increases the amount of revenue requirement to be collected from customers in 2020 and flows through to the revenue shortfall calculated in the first bullet in this scenario. Similar to the Commission's past direction to refund the RORA in a timely manner, the Company recommends that the WNRA owing to customers also be returned to customers as proposed rather than delaying its refund.

[1] $573,000 less DSM amortization costs of $127,447 incurred by the Company in 2020.
[2] $573,000 less DSM amortization costs of $157,198 incurred by the Company in 2019.

SCENARIO 2:
Please assume as follows:

- The Commission does not approve any revenue shortfall account.
- The CTGS accumulated reserve is recovered over a sixty-month period beginning January 1, 2021.
- The Hurricane Dorian costs ($3,002,900) are recovered using the 2019 RORA balance.
- MECL's share of the EE&C costs collected through the rate rider from March 1, 2019 to December 31, 2020 are remitted to PEIEC. The EE&C rate rider for the 2020/2021 collection period is reduced accordingly. Please provide all supporting calculations, including forecasts for the period from November 1, 2020 to December 31, 2020.
- The balance of the RORA account and WNR account are used to offset the ECAM balance. Any remaining RORA balance is refunded to ratepayers over a twelve (12) month period beginning January 1, 2021.
- The rates are implemented effective January 1, 2021 and the rate-setting period will end on February 28, 2022.
- All other requests made by MECL in the application are approved as filed.

Response:

IR-96 - Attachment 2 provides the rates and the rate impacts for Scenario 2 including changes to the proposed revenue requirement for 2020 and 2021, annual cost for a typical customer in each rate class, the energy charges per kWh, and rate base and return on rate base from those proposed in our January Filing.

In addition, supporting calculations of the various balances and rate riders or refunds are provided in page 2 of Attachment 5 – Supporting Calculations of Scenarios.

The Company also offers the following additional commentary on the assumptions provided in this scenario.

- The revenue shortfall in this scenario will increase the amount proposed in the response to IR-95 to $3,517,971, consistent with Scenario 1.

  Net of tax, this would result in an earnings shortfall of approximately $2.4 million and the Company's ROE would be 7.88 per cent, well below the maximum ROE of 9.35 per cent based on 40 per cent average common equity approved in Order UE19-08. This would also be well below returns in comparable jurisdictions. Further, a decision resulting in an impaired level of return has the potential to negatively impact the Company's business risk and financial risk profile which could, in turn, erode the Company's credit rating. Such outcomes ultimately lead to higher costs for customers in the long run.

The Company's 2020 average common equity will have a corresponding reduction of $1.2 million and the equity ratio will fall to 39.5 per cent compared to 39.8 per cent in Scenario 1 which contemplates approval of the revenue shortfall.

Section 24, paragraph 1 of the Electric Power Act (the "Act") states:

> *"Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, computed by using the rate base as fixed and determined by the Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Commission according to this Act and the rules and regulations made by the Commission hereunder."*

The revenue shortfall methodology and calculation has been reviewed by Grant Thornton. In their conclusion, Grant Thornton states in Section 4.4 Conclusion:

> *"…nothing has come to our attention that the proposed revenue shortfall...appears unreasonable. We did not note any discrepancies in the calculation of the proposed revenue shortfall and the components of the revenue shortfall are internally consistent with the Company's January 2020 filing…the Company's methodology does not appear unreasonable and is comparable to the methodology used by utilities in Newfoundland and Labrador."*

The Company respectfully submits that not approving the revenue shortfall effectively denies the Company any reasonable opportunity to earn the allowable return entitled under the Act.

- Amortizing the CTGS reserve variance over 60 months starting on January 1, 2021 increases the revenue requirement in 2021 by approximately $1.9 million which, in turn, increases the overall rate impact for customers in 2021.

- Recovering Hurricane Dorian costs using the 2019 RORA is as proposed in the January Filing and the response to IR-95.

- The current rates approved by the Commission do not include a rate rider for the PEIEC's EE&C plan. The confusion may be the result of an error in Section 7.1.2.2 of Grant Thornton's report identified in our letter to the Commission dated November 24, 2020 Application for an Order Approving Changes to the Schedule of Rates Effective March 1, 2020 and March 1, 2021 – *Comments on Grant Thornton Report.*

Although the Company has provided its position on the EE&C funding, if the Commission were to alternatively conclude that the Company is collecting DSM costs of $573,000 in base rates, this effectively increases the Company's 2020 Revenue Requirement from that originally proposed in the January Filing by $445,553[3]. This flows through to the revenue shortfall amount calculated in the first bullet in this scenario.

Similar treatment applied to the 2019 EE&C Plan would require a reduction to the RORA account of $415,802[4] as explained in our comments on the Grant Thornton Report.

- Applying the forecast RORA and WNRA balances on December 31, 2020 to the ECAM balance will reduce the forecast ECAM balance to nil on December 31, 2020 and there will be a forecast balance of $1,287,772 in the RORA to be refunded to customers beginning January 1, 2021 after taking into consideration the adjustments proposed in this scenario.

  In this scenario, the Company has calculated the refund rate based on the forecast December 31, 2020 RORA balance being refunded over a 12 month period effective January 1, 2021. The Company would caution that refunding the balance over 12 months could result in an over-refund of RORA as all other rate assumptions are based on a 14 month rate setting period. The Company respectfully suggests calculating the refund rate over the full 14 month rate setting period, January 1, 2021 to February 28, 2022.

  In the January Filing and in our response to IR-95, the Company has proposed amortizing the balance of the WNRA on December 31, 2019 against the 2020 revenue requirement thereby reducing the revenue required to be collected from customers through basic rates. Applying the WNRA balance to ECAM as proposed in this scenario increases the amount of revenue requirement to be collected from customers in 2020 and flows through to the revenue shortfall calculated in the first bullet in this scenario. Similar to the Commission's past direction to refund the RORA in a timely manner, the Company recommends that the WNRA owing to customers also be returned to customers as proposed rather than delaying its refund.

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3 $573,000 less DSM amortization costs of $127,447 incurred by the Company in 2020.
4 $573,000 less DSM amortization costs of $157,198 incurred by the Company in 2019.

SCENARIO 3:
Please assume as follows:

- The Commission does not approve any revenue shortfall account.
- The CTGS accumulated reserve is deferred to the next rate setting period.
- The Hurricane Dorian costs ($3,002,900) are recovered using the 2019 RORA balance.
- MECL's share of the EE&C costs collected through the rate rider from March 1, 2019 to December 31, 2020 are remitted to PEIEC. The EE&C rate rider for the 2020/2021 collection period is reduced accordingly. Please provide all supporting calculations, including forecasts for the period from November 1, 2020 to December 31, 2020.
- The RORA account balance is used to offset the ECAM balance. The WNR account remains as deferred. Any remaining balance of the RORA account is refunded to ratepayers over a twelve (12) month period.
- The rates are implemented effective January 1, 2021 and the rate-setting period will end on February 28, 2022.
- All other requests made by MECL in the application are approved as filed.

Response:

IR-96 - Attachment 3 provides the rates and the rate impacts that arise from Scenario 3 including changes to the proposed revenue requirement for 2020 and 2021, annual cost for a typical customer in each rate class, the energy charges per kWh, and rate base and return on rate base from those proposed in our January Filing.

In addition, supporting calculations of the various balances and rate riders or refunds are provided on page 3 of Attachment 5 – Supporting Calculations of Scenarios.

The Company also offers the following additional commentary on the assumptions provided in this scenario.

- The revenue shortfall in this scenario will increase the amount proposed in the response to IR-95 to $3,517,971, consistent with Scenarios 1 and 2.

  Net of tax, this would result in an earnings shortfall of approximately $2.4 million and the Company's ROE would be 7.88 per cent, well below the maximum ROE of 9.35 per cent based on 40 per cent common equity approved in Order UE19-08. This would also be well below returns in comparable jurisdictions. Further, a decision resulting in an impaired level of return has the potential to negatively impact the Company's business risk and financial risk profile which could, in turn, erode the Company's credit rating. Such outcomes ultimately lead to higher costs for customers in the long run.

  The Company's 2020 average common equity will have a corresponding reduction of $1.2 million and the equity ratio will fall to 39.5 per cent compared to 39.8 per cent in Scenario 1 which contemplates approval of the revenue shortfall.

Section 24, paragraph 1 of the Electric Power Act (the "Act") states:

> *"Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, computed by using the rate base as fixed and determined by the Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Commission according to this Act and the rules and regulations made by the Commission hereunder."*

The revenue shortfall methodology and calculation has been reviewed by Grant Thornton. In their conclusion, Grant Thornton states in Section 4.4 Conclusion:

> *"…nothing has come to our attention that the proposed revenue shortfall...appears unreasonable. We did not note any discrepancies in the calculation of the proposed revenue shortfall and the components of the revenue shortfall are internally consistent with the Company's January 2020 filing…the Company's methodology does not appear unreasonable and is comparable to the methodology used by utilities in Newfoundland and Labrador."*

The Company respectfully submits that not approving the revenue shortfall effectively denies the Company any reasonable opportunity to earn the allowable return entitled under the Act.

- Deferral of the CTGS accumulated reserve until the next rate setting period is as proposed in the January Filing and the response to IR-95.

- Recovering Hurricane Dorian costs using the 2019 RORA is as proposed in the January Filing and the response to IR-95.

- The current rates approved by the Commission do not include a rate rider for the PEIEC's EE&C plan. The confusion may be the result of an error in Section 7.1.2.2 of Grant Thornton's report identified in our letter to the Commission dated November 23, 2020 Application for an Order Approving Changes to the Schedule of Rates effective March 1, 2020 and March 1, 2021 – *Comments on Grant Thornton Report.*

  Although the Company has provided its position on the EE&C funding, if the Commission were to alternatively conclude that the Company is collecting DSM costs of $573,000 in base rates, this effectively increases the Company's 2020 Revenue Requirement from that originally proposed in the January Filing by $445,553[5]. This flows through to the revenue shortfall amount calculated in the first bullet in this scenario.

  Similar treatment applied to the 2019 EE&C Plan would require a reduction to the RORA account of $415,802[6] as explained in our comments on the Grant Thornton Report.

[5] $573,000 less DSM amortization costs of $127,447 incurred by the Company in 2020.
[6] $573,000 less DSM amortization costs of $157,198 incurred by the Company in 2019.

- Applying the forecast RORA balance on December 31, 2020 to the ECAM balance will reduce the forecast ECAM balance to nil on December 31, 2020 and there will be a forecast balance of $128,072 in the RORA to be refunded to customers beginning January 1, 2021 after taking into consideration the adjustments proposed in this scenario.

  In this scenario, the Company has calculated the refund rate based on the forecast December 31, 2020 RORA balance being refunded over a 12 month period effective January 1, 2021. The Company would caution that refunding the balance over 12 months could result in an over-refund of RORA as all other rate assumptions are based on a 14 month rate setting period. Given the small balance remaining to be refunded to customers on December 31, 2020 in this scenario, the balance of any over-refund is not likely to be large. However, the Company respectfully suggests calculating the refund rate over the full 14 month rate setting period, January 1, 2021 to February 28, 2022 to mitigate this risk.

  In the January Filing and in our response to IR-95, the Company has proposed amortizing the balance of the WNRA on December 31, 2019 against the 2020 revenue requirement thereby reducing the revenue required to be collected from customers through basic rates. Continuing to defer the balance of the WNRA as proposed in this scenario increases the amount of revenue requirement to be collected from customers in 2020 and flows through to the revenue shortfall calculated in the first bullet in this scenario. Similar to the Commission's past direction to refund the RORA in a timely manner, the Company recommends that the WNRA owing to customers also be returned to customers as proposed rather than delaying its refund.

SCENARIO 4:

Please assume as follows:

- The Commission approves a revenue shortfall account. The balance of the revenue shortfall account is equal to the amount of revenue required for MECL to meet its 2020 rate of return calculated based on rates that are currently in effect (i.e. do not assume there was a rate increase on March 1, 2020). Please include the calculation of this amount based on actual results from January 1, 2020 until October 31, 2020, and forecast results from November 1, 2020 until December 31, 2020.
- The CTGS accumulated reserve is recovered over a sixty-month period beginning January 1, 2021.
- The Hurricane Dorian costs ($3,002,900) are recovered using the 2019 RORA balance.
- MECL's share of the EE&C costs collected through the rate rider from March 1, 2019 to December 31, 2020 are remitted to PEIEC. The EE&C rate rider for the 2020/2021 collection period is reduced accordingly. Please provide all supporting calculations, including forecasts for the period from November 1, 2020 to December 31, 2020.
- The RORA account balance is used to offset the ECAM balance. The WNR account remains as deferred. Any remaining balance of the RORA account is refunded to ratepayers over a twelve (12) month period.
- The rates are implemented effective January 1, 2021 and the rate-setting period will end on February 28, 2022.
- All other requests made by MECL in the application are approved as filed.

Response:

IR-96 - Attachment 4 provides the rates and the rate impacts that arise from Scenario 4 including changes to the proposed revenue requirement for 2020 and 2021, annual cost for a typical customer in each rate class, the energy charges per kWh, and rate base and return on rate base from those proposed in our January Filing.

In addition, supporting calculations of the various balances and rate riders or refunds are provided in page 4 of Attachment 5 – Supporting Calculations of Scenarios.

The Company also offers the following additional commentary on the assumptions provided in this scenario.

- The proposed revenue shortfall in this scenario will increase from the amount proposed in the response to IR-95 to $3,517,971, consistent with Scenarios 1 through 3.

  The increase in revenue shortfall reflects the year-to-date actual results from January 1, 2020 to October 31, 2020 and forecast results from November 1, 2020 to December 31, 2020, which includes the impact of lower than expected sales due to the pandemic as discussed in our response to IR-91 and IR-92. This increase is partially offset by lower net energy costs as a result of not changing the ECAM base rate on March 1, 2020.

The revenue shortfall also includes changes to the 2020 revenue requirement as a result of bullets 4 (recovery of EE&C Plan costs of $445,553) and 5 (continuing to defer the balance of the WNRA of $1,057,328).

- Amortizing the CTGS reserve variance over 60 months starting on January 1, 2021 increases the 2021 revenue requirement by approximately $1.9 million which, in turn, increases the overall rate impact for customers in 2021.

- Recovering Hurricane Dorian costs using the 2019 RORA is as proposed in the January Filing and the response to IR-95.

- The current rates approved by the Commission do not include a rate rider for the PEIEC's EE&C plan. The confusion may be the result of an error in Section 7.1.2.2 of Grant Thornton's report identified in our letter to the Commission dated November 24, 2020 Application for an Order Approving Changes to the Schedule of Rates effective March 1, 2020 and March 1, 2021 – *Comments on Grant Thornton Report.*

  Although the Company has provided its position on the EE&C funding, if the Commission were to alternatively conclude that the Company is collecting DSM costs of $573,000 in base rates, this effectively increases the Company's 2020 Revenue Requirement from that originally proposed in the January Filing by $445,553[7]. This flows through to the revenue shortfall amount calculated in the first bullet in this scenario.

  Similar treatment applied to the 2019 EE&C Plan would require a reduction to the RORA account of $415,802[8] as explained in our comments on the Grant Thornton Report.

- Applying the forecast RORA balance on December 31, 2020 to the ECAM balance will reduce the forecast ECAM balance to nil on December 31, 2020 and there will be a forecast balance of $128,072 in the RORA to be refunded to customers beginning January 1, 2021 after taking into consideration the adjustments proposed in this scenario.

  In this scenario, the Company has calculated the refund rate based on the forecast December 31, 2020 RORA balance being refunded over a 12 month period effective January 1, 2021. The Company would caution that refunding the balance over 12 months could result in an over-refund of RORA as all other rate assumptions are based on a 14 month rate setting period. Given the small balance remaining to be refunded to customers on December 31, 2020 in this scenario, the balance of any over-refund is not likely to be large. However, the Company respectfully suggests calculating the refund rate over the full 14 month rate setting period, January 1, 2021 to February 28, 2022 to mitigate this risk.

[7] $573,000 less DSM amortization costs of $127,447 incurred by the Company in 2020.
[8] $573,000 less DSM amortization costs of $157,198 incurred by the Company in 2019.

In the January Filing and in our response to IR-95, the Company has proposed amortizing the balance of the WNRA on December 31, 2019 against the 2020 revenue requirement thereby reducing the revenue required to be collected from customers through basic rates. Continuing to defer the balance of the WNRA as proposed in this scenario increases the amount of revenue requirement to be collected from customers in 2020 and flows through to the revenue shortfall calculated in the first bullet in this scenario. Similar to the Commission's past direction to refund the RORA in a timely manner, the Company recommends that the WNRA owing to customers also be returned to customers as proposed rather than delaying its refund.

The Commission may approve electric rates based on the above scenarios. With this in mind, please provide any comments that MECL may have with respect to each of these scenarios, including any details or information that may be pertinent to the Commission's decision.

Response:
With respect to the above noted scenarios, the Company provides the following additional comments.

CTGS Reserve Variance
In Section 9.0 of the January Filing, the Company proposed establishing a regulatory deferral account for the projected unrecovered depreciation and reserve variance amortization associated with the two-year gap in implementation of the 2017 Study. The Company proposed to recover the deferral in the next rate setting period with a target amortization of two years (2022 and 2023) for the following reasons.

The first reason was to mitigate the impact on customer rates that resulted from the adoption of the Gannett Fleming 2017 Depreciation Study depreciation rates effective January 1, 2020, as directed in Order UE19-08. This resulted in an increase of more than $5 million in the forecast depreciation expense compared to the depreciation expense recovered in 2019 rates.

Second, deferring the recovery of the CTGS reserve variance will allow the amount to be updated to reflect the results of a new depreciation study based on financial results up to December 31, 2020 and provide a more accurate calculation of the balance to be recovered.

Finally, deferring the recovery of the CTGS reserve balance until 2022 and 2023 will allow its recovery over the same period as the completion of the decommissioning activities.

Scenarios 1, 2 and 4 contemplate amortizing the CTGS reserve variance over five years beginning on January 1, 2021. The Company still considers the above noted reasons valid and recommends that the Commission defer the settlement of this matter until the next rate setting period. The Company maintains that the regulatory deferral should still be recognized and segregated from the capital asset value for proper disclosure and recognition for recovery.

Weather Normalization Reserve Account Balance
The Company proposed in Section 4.2 of the Application that the December 31, 2019 balance of the WNRA be fully returned to customers in 2020 by crediting the balance to the Company's income statement and thereby reducing the total revenue required to be recovered through rates.

In Scenarios 1 and 2, the Commission has proposed instead to apply the balance of the WNRA, along with the RORA balance, to the ECAM. This will reduce the ECAM balance to nil and result in a remaining balance in RORA to be refunded to customers. This approach will increase the 2020 revenue shortfall deferral as discussed in response to IR-96.

Whether the WNRA balance is amortized to the Company's income statement as proposed or refunded through the RORA balance, the revenue shortfall is increased accordingly, and the impact on customers and the Company is neutral.

However, Scenarios 3 and 4 propose continuing to defer the WNRA balance. This approach seems to contradict the Commission's position on other balances owing to customers, such as the RORA. Therefore, the Company respectfully recommends that the WRNA balance be returned to customers either as proposed in the January Filing or as an offset to ECAM/RORA.

With these considerations in mind, the Company respectfully submits a fifth scenario for consideration.

SCENARIO 5:

Assumptions as follows:

- The Commission approves a revenue shortfall account. The balance of the revenue shortfall account is equal to the amount of revenue required for Maritime Electric to meet its 2020 rate of return calculated based on rates that are currently in effect (i.e. do not assume there was a rate increase on March 1, 2020). Please include the calculation of this amount based on actual results from January 1, 2020 until October 31, 2020, and forecast results from November 1, 2020 until December 31, 2020.
- The CTGS accumulated reserve is deferred to the next rate setting period.
- The Hurricane Dorian costs ($3,002,900) are recovered using the 2019 RORA balance.
- The Commission decides that the Company is currently collecting DSM costs of $573,000 in base rates, this is effectively an increase in the Company's 2020 revenue requirement from originally proposed in the January Filing of $445,553 which flows through to the proposed revenue shortfall deferral balance. Similar treatment is also applied to the 2019 EE&C Plan requiring a reduction to the RORA balance of $415,802.
- The balance of the RORA and WNRA are used to offset the ECAM balance. Any remaining RORA balance is refunded to ratepayers over a twelve (12) month period beginning January 1, 2021.
- The rates are implemented effective January 1, 2021 and the rate-setting period will end on February 28, 2022.
- All other requests made by Maritime Electric in the January Filing are approved as filed.

IR-96 - Attachment 6 provides the rates and the rate impacts that arise from scenario 5 including changes to the proposed revenue requirement for 2020 and 2021, annual cost for a typical customer in each rate class, the energy charges per kWh, and rate base and return on rate base from those proposed in our January Filing.

In addition, supporting calculations of the various balances and rate riders or refunds are provided in page 5 of Attachment 5 – Supporting Calculations of Scenarios.

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

Section IR-91

ATTACHMENTS

2020 YTD Sales Compared to July 2019

Maritime Electric
Monthly Sales
2020 Budget (000's) - July 2019 Update Filing

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 20
Kilowatt Hour Sales													
Residential	76,821	72,020	63,304	62,704	51,222	46,067	45,167	48,176	47,742	45,945	54,763	69,873	683,806
General Service I	35,495	36,319	32,711	33,962	31,724	32,316	33,904	37,194	36,184	31,776	31,714	33,262	406,560
Large Industrial	13,834	11,959	12,352	13,630	14,060	13,333	14,547	14,334	14,365	12,968	12,838	13,379	161,600
Small Industrial	7,239	7,403	6,625	7,042	7,483	8,977	8,810	9,506	9,649	8,656	8,104	7,424	96,919
Street Lighting	412	408	405	401	399	397	396	396	395	394	394	393	4,791
Unmetered	220	206	207	207	207	208	206	206	208	208	208	220	2,510
	134,020	128,316	115,604	117,947	105,095	101,298	103,031	109,812	108,544	99,947	108,020	124,551	1,356,185

Maritime Electric
Monthly Sales
2020 YTD Actual (000's)

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 20
Kilowatt Hour Sales													
Residential	74,394	76,854	65,032	60,672	55,238	43,960	44,607	49,644	43,385	43,774			557,561
General Service I	35,246	36,787	33,656	29,835	26,588	26,335	29,398	32,741	30,909	28,821			310,316
Large Industrial	12,883	12,370	13,012	12,078	13,062	12,464	14,086	13,959	12,711	12,665			129,290
Small Industrial	7,255	7,332	6,744	6,711	6,363	8,139	8,498	8,486	8,421	8,343			76,292
Street Lighting	383	382	380	377	374	372	372	371	371	371			3,752
Unmetered	222	206	206	206	207	207	207	207	207	208			2,083
	130,383	133,931	119,030	109,879	101,833	91,477	97,168	105,409	96,004	94,182	-	-	1,079,295

Maritime Electric
Monthly Sales & Revenue
2020 Variance (000's)

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 20
Kilowatt Hour Sales													
Residential	(2,427)	4,833	1,728	(2,032)	4,016	(2,106)	(560)	1,468	(4,357)	(2,171)			(1,609)
General Service I	(249)	468	945	(4,127)	(5,135)	(5,981)	(4,506)	(4,453)	(5,275)	(2,954)			(31,268)
Large Industrial	(951)	411	659	(1,552)	(998)	(870)	(461)	(376)	(1,654)	(303)			(6,093)
Small Industrial	16	(70)	118	(331)	(1,120)	(838)	(313)	(1,020)	(1,228)	(313)			(5,100)
Street Lighting	(28)	(27)	(25)	(24)	(25)	(25)	(24)	(25)	(25)	(23)			(251)
Unmetered	2	(0)	(1)	(1)	(0)	(1)	1	2	(1)	(0)			1
	(3,637)	5,615	3,425	(8,068)	(3,263)	(9,821)	(5,863)	(4,403)	(12,540)	(5,765)	-	-	(44,319)

2020 YTD Sales Compared to July 2019

	2020 January 1 to October 31			
	Jul 2019 update (GWh)	**Actual (GWh)**	**Variance (GWh)**	Reason for variance:
Residential				
- Commercial Farm Customer Expansion	24.7	6.2	(18.5)	Load has not ramped up as expected, expect further delayed due to COVID
- space heating load	150.3	153.7	3.4	Heating Degree Days higher than 10 year average
- non-space heating loads	384.2	397.7	13.5	Attributed to COVID-19: more people working from home and closure of schools
subtotal	**559.2**	**557.6**	**(1.6)**	
General Service	341.5	310.3	(31.2)	Attributed to COVID-19: schools and shops closed starting in March
Small Industrial	135.4	129.3	(6.1)	Assumed to be due to COVID-19
Large Industrial	81.4	76.3	(5.1)	Customer planned expansion delayed, delay possibly extended due to COVID
Lighting	4.0	3.7	(0.3)	Underestimated rate of conversion to LED
Unmetered	2.1	2.1	-	
	1,123.6	**1,079.3**	**(44.3)**	

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

Section IR-93

ATTACHMENTS

July 2019 Forecast VS 2019 Actual

Comparison of July 2019 GRA Update Forecast to 2019 Actual		
Gross Operating Revenue	$	(1,077,768)
Net Energy Costs		2,686,199
Distribution and Transmission		(8,026)
Transmission - OATT		(382,015)
Corporate		296,545
Amortization		2,544,112
Financing Costs		(127,094)
WNRA		(430,777)
Corporate Taxes		2,264
Non-regulated Earnings		5,681
RORA Adjustment	**$**	**3,509,122**

Maritime Electric Financial Forecast Income Statement 2019 - July Update Forecast to Actual	Actuals 2019	Forecast 2019	Variance 2019	Comments
Operating Revenue				
Electric Revenue	201,654,319	203,854,637	(2,200,318)	Lower revenue due to lower sales than forecast.
Other Revenue	2,291,631	2,350,756	(59,125)	Reduced accrued revenue due to lower sales than forecast.
OATT	11,366,341	10,184,666	1,181,675	See Note 1 below.
	215,312,291	216,390,058	(1,077,768)	
Operating Expenses				
Energy Costs - Gross	127,020,670	130,993,753	(3,973,083)	See IR-93 Attachment 1 Page 3.
ECAM Refundable (Recoverable)	464,059	(822,825)	1,286,884	
Net Energy Costs	127,484,729	130,170,927	(2,686,199)	See IR-93 Attachment 1 Page 3.
Distribution and Transmission	7,997,163	7,989,137	8,026	Not a material variance.
Transmission - OATT	8,519,015	8,137,000	382,015	See Note 2 below.
Corporate	10,076,755	10,373,300	(296,545)	See IR-93 Attachment 1 Page 4.
	154,077,661	156,670,364	(2,592,703)	
Amortization				
Amortization - Fixed Assets	23,337,238	25,871,548	(2,534,310)	Order UE19-08 did not approve the adjustments to depreciation rates proposed in the GRA for 2019.
Amortization of Pt Lepreau Settlement & Community Outre	250,598	260,400	(9,802)	Not a material variance.
	23,587,836	26,131,948	(2,544,112)	
Operating Income	37,646,794	33,587,746	4,059,048	
Other Expenses				
Long Term Debt Charges	12,442,150	12,442,150	-	
Short Term Debt Charges	1,236,733	1,061,414	175,319	Variances to short-term financing requirements and interest rate assumptions to reflect current prime rate of 3.95%.
Allowance for Funds	(474,433)	(429,000)	(45,433)	Based on actual capital for 2019.
Amortization of Financing Costs	13,004	15,797	(2,793)	Not a material variance.
Subtotal Financing Costs	13,217,455	13,090,361	127,094	
Weather Normalization	766,345	335,568	430,777	Actual HDD variances compared to 10 year average (see Appendix 4 Schedule 4 of Application) and $45K adjustment to PYs based on GT review in fall of 2019.
Due to Cust - ROE/Return on Rate Base Adj	3,509,123	-	3,509,123	See IR-93 Attachment 1 Page 1
	17,492,923	13,425,929	4,066,994	
Net Earnings Before Income Taxes	20,153,872	20,161,817	(7,945)	Not a material variance.
Income Taxes	6,299,722	6,301,986	(2,264)	Not a material variance.
Net Earnings, Non-regulated for F/S Purposes	13,854,150	13,859,831	(5,681)	Not a material variance.
Regulatory Adjustments				
Fortis Inc Fees	408,480	409,860	(1,380)	Not a material variance.
Net Earnings - Regulated	14,262,630	14,269,691	(7,061)	Not a material variance.
Return on Average Common Equity, Non-regulated	9.08	9.08	9.08	

Notes:

1 Variance reflects a different rate assumed in the 2019 forecast.

2 Variance reflects a different rate assumed in the 2019 forecast, causing an increase of $453K, partially offset by lower OATT administration costs of $71K due to reduced labour costs.

July 2019 Forecast VS 2019 Actual

RECONCILIATION OF GROSS ENERGY COSTS				
Total Gross Energy Costs per Forecast			$	130,993,753
Variance on Insurance, Property Tax & Training				(50,089)
Less: Lepreau & Dal Debt Recovery not approved by Order UE19-08	(4 months @ $478,321)	Note 1		(1,913,284)
Lower Energy Purchase costs (NPP) due to lower sales				(1,050,790)
Lower On-Island Generation and ECC Costs		Note 2		(958,983)
Total Variance				**(3,973,146)**
Actual Gross Energy Costs for 2019			$	127,020,607

-1

Reconciliation of Net Energy Costs	Actuals 2019	Forecast 2019	Variance 2019
Net Purchased and Produced Energy (kWh)	1,385,298,410	1,402,929,515	(17,631,105)
ECAM Rate - Note 3	91.61	92.35	
Energy Costs Charged to the Income Statement	126,907,187	129,556,458	
Insurance, Property Tax & Training	828,143	878,232	
Amortization Lepreau & DSM	(250,598)	(263,763)	
Net Energy Costs	**$ 127,484,732**	**$ 130,170,927**	**$ (2,686,195)**

Note 1

- In the GRA Application, the Company proposed to include the cost of the Lepreau and Dal Debt Recovery in revenue requirement as a flow thru in ECAM. In Order UE19-08, the Commission ordered the recovery to continue as a rate rider.

Note 2

ECC cost saving mainly due to removal of ECC "spare" position and lower overtime and double-time than forecast. See response to 2018 GRA Commission IR #26.	$	108	K
Generation Fuel Savings for plant heating and generation.		251	K
Redeployment of production dept staff to other depts with long-term layup and eventual decommissioning of CTGS.		400	K
Materials, consulting and other costs for maintenance below forecast		200	K
Total	$	959	K

Note 3

- In the July 2019 update, the Company proposed changing the ECAM base rate to $93.80 effective September 1, 2019. The forecast ECAM rate of $92.35 above is the average forecast rate for the year (January to August @ $91.61 and September to December @ $93.80). See update to GRA Appendix 4 filed with July 2019 Update.

GRA SCHEDULE 10-1				
General and Administrative Expenses ($)				
Description	**2019 Forecast**	**2019 Actual**	**2019 Variance**	
Customer Service and Meter Reading	$ 2,131,900	$ 1,922,752	$ (209,148)	Note 1
Finance and Accounting	1,497,900	1,392,343	(105,557)	Wages & benefits were approximately $70K lower due employee parental leave and the remainder is primarily savings in postage costs due to customer transitions to electronic billing.
Corporate Communications and Public Affairs	447,400	414,198	(33,202)	Lower requests for donations than historical and forecast levels.
Information Technology	781,400	694,990	(86,410)	Primarily the result of forecast costs for cybersecurity assessment and ESRI Atlantic Utilities Conference deferred to 2020.
Regulation	1,082,800	1,064,830	(17,970)	Lower than forecast consulting and regulatory assessment for GRA hearing.
Directors' Fees	407,800	365,327	(42,473)	Adjustments to directors' fees and lower travel costs.
General Property - Tax & Maintenance	711,100	692,068	(19,032)	Lower than forecast substation repairs and maintenance costs.
Corporate Services and Support	2,719,000	2,938,247	219,247	See Schedule 10-2 below.
Fortis Inc Costs	594,000	592,000	(2,000)	Note Fortis Inc. fees are not included in regulatory earnings (adj on Line 45 of July 19 Forecast vs Actual tab).
Total	**$ 10,373,299**	**$ 10,076,755**	**$ (296,545)**	

GRA SCHEDULE 10-2				
Corporate Services and Support				
Description	**2019 Forecast**	**2019 Actual**	**2019 Variance**	
Employee Future Benefit Costs	$ (987,900)	$ (1,087,796)	$ (99,896)	Actual reflects 2019 Actuarial Report.
Employee Training	25,200	(22,926)	(48,126)	Timing of Government Skills training funding for 2018, received in 2019.
Human Resources	175,200	198,286	23,086	Higher than forecast labour due to overlap of new hire to replace an employee planning to retire to allow transition of knowledge.
Insurance	40,200	38,999	(1,201)	Not material.
Legal	178,000	208,743	30,743	Increased legal expenses related to GRA hearing.
Corporate Services	2,895,800	3,148,346	252,546	Forecast based on 2018 actual and there were variances due to changes in the relative valuation of variable compensation components.
Health Safety & Environment	109,100	129,373	20,273	Higher than forecast labour due to overlap of new hire to replace an employee planning to retire to allow transition of knowledge.
Internal Audit	94,000	89,888	(4,112)	New internal auditor hired in 2019.
System Planning & Engineering	189,400	235,334	45,934	Added planning engineer transferred from another department.
Total	**$ 2,719,000**	**$ 2,938,247**	**$ 219,247**	

Note 1 - Customer Service & Meter Reading
- Wages/benefits & training costs for customer service were approximately $115K below budget due to parental leaves/retirements and redeployments to other departments to cover sick leave and work load requirements.
- Write-offs for uncollectable accounts were down $73K on a forecast of $250K. The five year average write-offs for 2014-2018 is $235,000.
- Damage claims were down $24K on a budget of $52K. The five year average for damage claims for 2014-2018 is $58K.

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

Section IR-95

ATTACHMENTS

2020 Revenue Shortfall Deferral

Maritime Electric Sales & Revenue Forecast (000's) 2019 - 2021 Plan	2018 Actual	2019 Actual	2020 Budget	2021 Budget	January 2020 Application 2020 Budget	January 2020 Application 2021 Budget	2020 Revenue Shortfall (000s)
Kilowatt Hour Sales							
Residential	612,763	640,951	676,711	707,369	676,711	707,369	
General Service	393,556	392,791	403,240	412,606	403,240	412,606	
Large Industrial	151,703	154,031	159,500	161,000	159,500	161,000	
Small Industrial	91,653	91,698	94,280	96,469	94,280	96,469	
Street Lighting	5,176	4,910	4,791	4,550	4,791	4,550	
Unmetered	2,458	2,479	2,510	2,535	2,510	2,535	
	1,257,309	1,286,860	1,341,031	1,384,529	1,341,031	1,384,529	
Growth Rate							
Residential	6.20%	4.60%	5.58%	4.53%	5.58%	4.53%	
General Service I	2.24%	-0.19%	2.66%	2.32%	2.66%	2.32%	
Large Industrial	13.53%	1.53%	3.55%	0.94%	3.55%	0.94%	
Small Industrial	-12.35%	0.05%	2.82%	2.32%	2.82%	2.32%	
Street Lighting	-6.22%	-5.13%	-2.43%	-5.03%	-2.43%	-5.03%	
Unmetered	1.76%	0.87%	1.23%	1.00%	1.23%	1.00%	
	4.08%	2.35%	4.21%	3.24%	4.21%	3.24%	
Revenue							
Residential	104,127	108,631	114,212	120,252	115,517	120,252	
General Service I	63,326	63,553	64,982	67,174	65,818	67,174	
Large Industrial	13,701	13,944	14,164	14,277	14,366	14,277	
Small Industrial	12,714	12,768	13,031	13,452	13,201	13,452	
Street Lighting	2,382	2,324	2,271	2,197	2,307	2,197	
Unmetered	431	435	421	432	428	432	
	196,681	201,654	209,080	217,785	211,637	217,785	**$2,557**
Other Revenue							
Penalty Revenue	656	617	671	706	678	706	
Service Connections	472	437	497	521	503	521	
Growth Rate							
Residential	7.49%	4.33%	5.14%	5.29%	6.34%	4.10%	
General Service I	4.67%	0.36%	2.25%	3.37%	3.56%	2.06%	
Large Industrial	19.33%	1.77%	1.57%	0.80%	3.03%	-0.62%	
Small Industrial	(6.80%)	0.42%	2.06%	3.23%	3.39%	1.90%	
Street Lighting	(1.77%)	-2.43%	-2.29%	-3.22%	-0.71%	-4.76%	
Unmetered	4.51%	0.91%	-3.17%	2.57%	-1.69%	1.02%	
	6.13%	2.53%	3.68%	4.16%	4.95%	2.90%	
Unit Revenue							
Residential	0.1699	0.1695	0.1688	0.1700	0.1707	0.1700	
General Service I	0.1609	0.1618	0.1612	0.1628	0.1632	0.1628	
Large Industrial	0.0903	0.0905	0.0888	0.0887	0.0901	0.0887	
Small Industrial	0.1387	0.1392	0.1382	0.1394	0.1400	0.1394	
Street Lighting	0.4602	0.4733	0.4740	0.4830	0.4816	0.4830	
Unmetered	0.1754	0.1754	0.1678	0.1704	0.1704	0.1704	
	0.1564	0.1567	0.1559	0.1573	0.1578	0.1573	
Customer Growth Rate							
Residential		1.67%	1.67%	1.64%	1.67%	1.64%	
Other		1.52%	1.58%	1.55%	1.58%	1.55%	

Revised Energy Charges per kWh Other Amounts

			ORIGINALLY PROPOSED			REVISED	
Application Section	Description	Description of Changes from Application	2020	2021		2020*	2021
3.0	PROVINCIAL COSTS RECOVERABLE	2020 - No change to rate rider since March 1, 2018	0.0042	0.0041		0.0054	0.0040
		2021 - Adjusted to reflect 14 month rate period (Jan 1/21-Feb 28/22)					
	PEIEC EE & C PLAN	2020 - No approved change to basic rates	0.0015	0.0008		-	0.0019
		2021 - Adjusted to collect 2019-2021 funding requirement & 14 month collection period					
	CABLE CONTINGENCY FUND	2020 - No change to rate rider since March 1, 2018	-	-		0.0003	-
4.1	ECAM	2020 - No change to collection rate since March 1, 2018					
		January 1, 2021 collection rate based on formula set out in Section N-0 of Rules & Regs	0.0020	0.0001		0.0006	0.0016
4.3	RORA	2020 - No change to rate rider since March 1, 2018	(0.0055)	-		(0.0035)	(0.0023)
		2021 - Forecast balance of RORA on December 31, 2020 returned to customers over 14 months (Jan 1/21-Feb 28/22)					
Schedule 11-4	Energy Charges per kWh - Other Amounts (B)		0.0022	0.0050		0.0028	0.0053

** Amounts reflect riders in effect since March 1, 2018.*

Revised Energy Charges per kWh Other Amounts

Costs Recoverable From Customers on Behalf of Province

January 1, 2021 - February 28, 2022		Annual	Revised (14 Months)
A.	Funding Requirement	$ 5,717,652	$ 6,670,594
B.	Sales (kWh)	January, 2021 - February 28, 2022	1,659,431,460
C.	Collection Rate ($/kWh) (A/B)		0.0040

Revised Energy Charges per kWh Other Amounts

PEIEC EE&C Plan Rate Rider - UE19-03

		2019/2020 Year 2	2020/2021 Year 3	2021/2022 Based on Year 3	TOTAL
Funding Requirement per PEIEC Application		$ 970,000	$ 1,200,000		
Maritime Electric Share per PEIEC Application		90.00%	89.90%		
Required Funding from Maritime Electric					
Customers per PEIEC Application	A	$ 900,000	$ 1,100,000	$ 1,100,000	$ 3,100,000

Forecast Sales (MWh) - January 1, 2021 to February 28, 2022			
Residential		866,361	
General Service I		487,001	
Large Industrial		186,467	
Small Industrial		111,346	
Street Lighting		5,287	
Unmetered		2,970	
Total MWh	B	1,659,431	
PEIEC EE&C Plan Rate Rider per kWh	A/(B x 1000)		0.0019

Revised Energy Charges per kWh Other Amounts

Based on Formula in Section N-0 of Rates Rules & Regulations Calculation of ECAM Rate Adjustment Applied to Customers' Bills				
Forecast ECAM Balance, October 31, 2020	N-0, Item 6	$	2,281,963	
kWh Sales - January 1, 2021 - December 31, 2021	N-0, Item 7		1,384,528,646	
Collection Rate	N-0, Item 8	$		0.0016

Revised Energy Charges per kWh Other Amounts

Forecast Post-2015 RORA Balance – February 29, 2020		$6,977,418
2019 RORA	$3,509,123	
Less: Write Off of Deferred Dorian Costs	(3,002,882)	506,241
RORA Balance Available for Refund		**$7,483,659**

Forecast Refund March 1 - December 31, 2020			
Forecast Sales March 1, 2020 – December 31, 2020 (kWh)	1,086,154,093		
RORA Refund Rate per kWh (March 1, 2020 – December 31, 2020)	$ 0.00345		3,747,232
Balance to be Refunded - January 1, 2021 - February 28, 2022	A		$3,736,427
Forecast Sales (MWh) - January 1, 2021 to February 28, 2022	B		1,659,431,460
Refund Rate - January 1, 2021 to February 28, 2022	= A / B	$	0.0023

Impact Proposed January 1, 2021 Implementation

Revenue Requirement ($)						
	Original Application Proposed		Proposed IR 95		Difference from Proposed	
	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 162,897,200	$ 169,336,300	$ -	$ -
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,902,500	12,874,200	58,100	19,900
Amortization - Fixed Assets	28,572,100	26,202,300	28,572,100	26,202,300	-	-
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900	-	-	-
Amortization - Rate Delay Deferral **	-	-	-	2,191,700	-	2,191,700
Income Tax Expense	6,742,200	6,978,200	6,742,900	6,978,900	700	700
Return on Equity***	14,842,900	15,371,400	14,844,500	15,372,800	1,600	1,400
Total Revenue Requirement	**$ 229,122,500**	**$ 231,002,500**	**$ 229,182,900**	**$ 233,216,200**	**$ 60,400**	**$ 2,213,700**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	(1,057,300)	-	-	-
Other Revenue	(13,425,300)	(13,217,400)	(16,042,600)	(13,274,100)	(2,617,300)	(56,700)
Revenue Requirement to be Collected through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 209,080,100**	**$ 219,942,100**	**$ (2,556,900)**	**$ 2,157,000**

* *Excluding Fortis Inc. Costs*

** *Remaining balance of $365,300 will be collected in January & February 2022*

*** *Before Disallowable Costs*

Impact Proposed January 1, 2021 Implementation

Impact on Annual Cost March 1 - February 28						
	Proposed Rates IR 95			Original Application Proposed Rates		
Period March 1 - February 28	**2019/20**	**2020/21**	**2021/22**	**2019/20**	**2020/21**	**2021/22**
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,451.94	$ 1,493.70	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.6%	2.9%	0.0%	1.1%	1.2%
Total Cost	$ 1,548.08	$ 1,556.84	$ 1,600.69	$ 1,548.08	$ 1,564.45	$ 1,582.58
	-2.4%	0.6%	2.8%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,423.74	$ 1,465.50	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.6%	2.9%	0.0%	1.1%	1.2%
Total Cost	$ 1,515.65	$ 1,524.42	$ 1,568.26	$ 1,515.65	$ 1,532.02	$ 1,550.15
	-2.4%	0.6%	2.9%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,782.31	$ 23,439.77	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.6%	2.9%	0.0%	1.1%	1.2%
Total Cost	$ 26,048.45	$ 26,199.66	$ 26,955.74	$ 26,048.45	$ 26,345.02	$ 26,650.62
	0.0%	0.6%	2.9%	0.0%	1.1%	1.2%

Impact Proposed January 1, 2021 Implementation

Composition of Total Energy Charge per kWh by Rate Class - January 1, 2021 Rate Implementation	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1448	2.8%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1145	2.8%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1788	2.8%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1158	2.8%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1751	2.8%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0868	2.8%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0692	0.9%
Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0016	186.6%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0040	-25.0%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0019	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0023)	-34.6%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0053	88.7%
Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1501	4.4%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1198	4.9%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1841	4.2%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1211	4.9%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1804	4.2%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0921	5.6%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0745	4.3%

* Rate changes effective March 1.

January 2020 Rate Application
Supplemental Information - 2019, 2020 and 2021 Inputs

Calculation of Rate Base ($)			Proposed in Original Application		Proposed IR 95		Difference from Proposed	
Components	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 712,215,800	$ 693,668,900	-	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	-	-	-	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,903,600)	(231,933,900)	-	-
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(24,598,000)	(25,496,000)	-	-
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(19,754,900)	(26,216,000)	(700)	(1,400)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	1,671,600	(554,000)	1,599,400	(75,900)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-			2,556,900	365,300	2,556,900	365,300
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(8,102,700)	(5,267,100)	(2,255,400)	(619,000)
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	9,654,500	-	-
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,852,400	6,098,100	-	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 414,509,400**	**$ 424,710,800**	**$ 1,900,200**	**$ (331,000)**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 403,878,378**	**$ 419,610,100**	**$ 950,100**	**$ 784,600**

Calculation of Return on Average Rate Base ($) & (%)		As Proposed		Proposed IR 95		Difference from Proposed	
	2019 Actual	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 229,182,900	$ 233,216,200	$ 60,400	$ 2,213,700
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(162,897,200)	(169,336,300)	-	-
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	66,271,900	63,865,400	60,400	2,213,700
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,572,100)	(26,202,300)	-	-
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(2,451,700)	-	(2,191,700)
	(23,587,836)	(31,795,800)	(26,462,300)	(31,795,800)	(28,654,000)	-	(2,191,700)
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	34,476,100	35,211,400	60,400	22,000
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(6,742,900)	(6,978,900)	(700)	(700)
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 27,733,200	$ 28,232,500	59,700	21,300
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 403,878,378	$ 419,610,100	950,100	784,600
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.86%**	**6.73%**	**-0.01%**	**-0.01%**

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

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

Section IR-96

ATTACHMENTS

Scenario 1 Impact

Revenue Requirement ($)						
	Original Application Proposed		IR 96 Scenario 1		Difference from Proposed	
	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 158,227,200	$ 169,389,200	$ (4,670,000)	$ 52,900
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,785,200	12,923,900	(59,200)	69,600
Amortization - Fixed Assets	28,572,100	26,202,300	28,386,200	28,131,500	(185,900)	1,929,200
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900	-	-	-
Amortization - Rate Delay Deferral **	-	-	-	3,015,400	-	3,015,400
Income Tax Expense	6,742,200	6,978,200	6,741,700	6,978,800	(500)	600
Return on Equity***	14,842,900	15,371,400	14,843,000	15,372,700	100	1,300
Total Gross Electric Revenue	**229,122,500**	**231,002,500**	**224,207,000**	**236,071,500**	**(4,915,500)**	**5,069,000**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	102,300	-	1,159,600	-
Other Revenue	(13,425,300)	(13,217,400)	(16,749,300)	(13,292,900)	(3,324,000)	(75,500)
Revenue Requirement to be Collected Through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 204,557,100**	**$ 222,778,600**	**$ (7,079,900)**	**$ 4,993,500**

* *Excluding Fortis Inc. Costs*

** *Remaining balance of $502,600 will be collected in January & February 2022*

*** *Before Disallowable Costs*

Scenatio 1 Impact

Impact on Annual Cost March 1 - February 28						
	IR 96 Scenario 1			Original Application Proposed Rates		
March 1 - February 28	2019/20	2020/21	2021/22	2019/20	2020/21	2021/22
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,453.70	$ 1,505.46	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.7%	3.6%	0.0%	1.1%	1.2%
Total Cost	$ 1,548.08	$ 1,558.69	$ 1,613.04	$ 1,548.08	$ 1,564.45	$ 1,582.58
	-2.4%	0.7%	3.5%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,425.50	$ 1,477.26	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.7%	3.6%	0.0%	1.1%	1.2%
Total Cost	$ 1,515.65	$ 1,526.27	$ 1,580.61	$ 1,515.65	$ 1,532.02	$ 1,550.15
	-2.4%	0.7%	3.6%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,809.40	$ 23,620.90	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.7%	3.6%	0.0%	1.1%	1.2%
Total Cost	$ 26,048.45	$ 26,230.81	$ 27,164.03	$ 26,048.45	$ 26,345.02	$ 26,650.62
	0.0%	0.7%	3.6%	0.0%	1.1%	1.2%

Scenatio 1 Impact

Composition of Total Energy Charge per kWh by Rate Class - IR 96 Scenario 1	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1470	4.3%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1162	4.3%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1815	4.4%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1175	4.4%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1777	4.3%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0881	4.4%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0706	2.9%
Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ -	-100.0%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0040	-25.0%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0013	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0009)	-73.0%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0044	57.1%
Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1514	5.4%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1206	5.6%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1859	5.2%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1219	5.6%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1821	5.2%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0925	6.1%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0750	5.0%

* Rate changes effective March 1.

Scenario 1 Impact

January 2020 Rate Application
Supplemental Information - 2019, 2020 and 2021 Inputs

Calculation of Rate Base ($)								
			Proposed in Original Application		IR 96 Scenario 1		Difference from Proposed	
Components	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 705,485,600	$ 693,668,900	(6,730,200.00)	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	(2,950,000)	-	(2,950,000.00)	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,717,700)	(231,746,300)	185,900	187,600.00
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(23,476,600)	(24,411,500)	1,121,400.00	1,084,500.00
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(23,915,700)	(30,658,700)	(4,161,500)	(4,444,100)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	-	3,500	(72,200)	481,600
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-			3,518,000	502,600	3,518,000	502,600
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(1,287,800)	-	4,559,500	4,648,100
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	7,723,600	-	(1,930,900)
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,750,800	6,098,100	(101,600)	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 407,978,500**	**$ 425,571,200**	**$ (4,630,700)**	**$ 529,400**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 400,612,928**	**$ 416,774,900**	**$ (2,315,350)**	**$ (2,050,600)**

Scenario 1 Impact

Calculation of Return on Average Rate Base ($) & (%)							
		As Proposed		IR 96 Scenario 1		Difference from Proposed	
	2019 Actual	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 224,207,000	$ 236,071,500	$ (4,915,500)	$ 5,069,000
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(158,227,200)	(169,389,200)	4,670,000	(52,900)
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	65,966,000	66,667,800	(245,500)	5,016,100
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,386,200)	(28,131,500)	185,900	(1,929,200)
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(3,275,400)	-	(3,015,400)
	(23,587,836)	(31,795,800)	(26,462,300)	(31,609,900)	(31,406,900)	185,900	(4,944,600)
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	34,356,100	35,260,900	(59,600)	71,500
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(6,741,700)	(6,978,800)	500	(600)
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 27,614,400	$ 28,282,100	(59,100)	70,900
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 400,612,928	$ 416,774,900	(2,315,350)	(2,050,600)
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.89%**	**6.79%**	**0.02%**	**0.05%**

Scenario 2 Impact

IR-96 - Scenario 2 Revenue Requirement ($)						
	Original Application Proposed		IR 96 Scenario 2		Difference from Proposed	
	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 158,227,200	$ 169,389,200	$ (4,670,000)	$ 52,900
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,785,200	13,044,600	(59,200)	190,300
Amortization - Fixed Assets	28,572,100	26,202,300	28,386,200	28,131,500	(185,900)	1,929,200
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900	-	-	-
Amortization - Rate Delay Deferral	-	-	-	-	-	-
Income Tax Expense	6,742,200	6,978,200	5,649,100	6,938,100	(1,093,100)	(40,100)
Return on Equity**	14,842,900	15,371,400	12,419,600	15,282,000	(2,423,300)	(89,400)
Total Gross Electric Revenue	**229,122,500**	**231,002,500**	**220,691,000**	**233,045,400**	**(8,431,500)**	**2,042,900**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	102,300	-	1,159,600	-
Other Revenue	(13,425,300)	(13,217,400)	(13,233,300)	(13,272,300)	192,000	(54,900)
Revenue Requirement to be Collected Through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 204,557,100**	**$ 219,773,100**	**$ (7,079,900)**	**$ 1,988,000**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

Scenario 2 Impact

Impact on Annual Cost March 1 - February 28						
	IR 96 Scenario 2			Original Application Proposed Rates		
March 1 - February 28	**2019/20**	**2020/21**	**2021/22**	**2019/20**	**2020/21**	**2021/22**
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,450.58	$ 1,486.74	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.5%	2.5%	0.0%	1.1%	1.2%
Total Cost	**$ 1,548.08**	**$ 1,555.41**	**$ 1,593.39**	**$ 1,548.08**	**$ 1,564.45**	**$ 1,582.58**
	-2.4%	0.5%	2.4%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,422.38	$ 1,458.54	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.5%	2.5%	0.0%	1.1%	1.2%
Total Cost	**$ 1,515.65**	**$ 1,522.99**	**$ 1,560.96**	**$ 1,515.65**	**$ 1,532.02**	**$ 1,550.15**
	-2.4%	0.5%	2.5%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,761.40	$ 23,332.90	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.5%	2.5%	0.0%	1.1%	1.2%
Total Cost	**$ 26,048.45**	**$ 26,175.61**	**$ 26,832.83**	**$ 26,048.45**	**$ 26,345.02**	**$ 26,650.62**
	0.0%	0.5%	2.5%	0.0%	1.1%	1.2%

Scenario 2 Impact

Composition of Total Energy Charge per kWh by Rate Class IR 96 Scenario 2	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1446	2.6%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1144	2.7%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1786	2.7%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1156	2.7%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1749	2.7%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0867	2.7%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0694	1.2%
Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ -	-100.0%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0040	-25.0%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0013	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0009)	-73.0%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0044	57.1%
Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1490	3.7%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1188	4.0%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1830	3.6%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1200	4.0%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1793	3.6%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0911	4.5%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0738	3.4%

* Rate changes effective March 1.

January 2020 Rate Application Supplemental Information - 2019, 2020 and 2021 Inputs Calculation of Rate Base ($)								
			Proposed in Original Application		IR 96 Scenario 2		Difference from Proposed	
Components	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 705,485,600	$ 693,668,900	(6,730,200)	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	(2,950,000)	-	(2,950,000)	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,717,700)	(231,746,300)	185,900	187,600
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(23,476,600)	(24,411,500)	1,121,400	1,084,500
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(22,823,100)	(29,525,300)	(3,068,900)	(3,310,700)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	-	3,500	(72,200)	481,600
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-			-	-	-	-
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(1,287,800)	-	4,559,500	4,648,100
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	7,723,600	-	(1,930,900)
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,750,800	6,098,100	(101,600)	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 405,553,100**	**$ 426,202,000**	**$ (7,056,100)**	**$ 1,160,200**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 399,400,228**	**$ 415,877,600**	**$ (3,528,050)**	**$ (2,947,900)**

Calculation of Return on Average Rate Base ($) & (%)							
		As Proposed		IR 96 Scenario 2		Difference from Proposed	
	2019 Actual	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 220,691,000	$ 233,045,400	$ (8,431,500)	$ 2,042,900
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(158,227,200)	(169,389,200)	4,670,000	(52,900)
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	62,450,000	63,641,700	(3,761,500)	1,990,000
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,386,200)	(28,131,500)	185,900	(1,929,200)
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(260,000)	-	-
	(23,587,836)	(31,795,800)	(26,462,300)	(31,609,900)	(28,391,500)	185,900	(1,929,200)
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	30,840,100	35,250,200	(3,575,600)	60,800
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(5,649,100)	(6,938,100)	1,093,100	40,100
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 25,191,000	$ 28,312,100	(2,482,500)	100,900
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 399,400,228	$ 415,877,600	(3,528,050)	(2,947,900)
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.31%**	**6.81%**	**-0.56%**	**0.07%**

Scenario 3 Impact

Revenue Requirement ($)						
	Original Application Proposed		**IR 96 Scenario 3**		**Difference from Proposed**	
	2020 Forecast	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 158,227,200	$ 169,389,200	$ (4,670,000)	$ 52,900
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,782,500	13,073,000	(61,900)	218,700
Amortization - Fixed Assets	28,572,100	26,202,300	28,386,200	26,200,600	(185,900)	(1,700)
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900	-	-	-
Amortization - Rate Delay Deferral **	-	-	-	-	-	-
Income Tax Expense	6,742,200	6,978,200	5,649,400	6,938,400	(1,092,800)	(39,800)
Return on Equity**	14,842,900	15,371,400	12,420,100	15,282,700	(2,422,800)	(88,700)
Total Gross Electric Revenue	**229,122,500**	**231,002,500**	**220,689,100**	**231,143,900**	**(8,433,400)**	**141,400**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	102,300	-	1,159,600	-
Other Revenue	(13,425,300)	(13,217,400)	(13,231,300)	(13,260,300)	194,000	(42,900)
Revenue Requirement to be Collected Through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 204,557,200**	**$ 217,883,600**	**$ (7,079,800)**	**$ 98,500**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

Scenario 3 Impact

Impact on Annual Cost March 1 - February 28						
	IR 96 Scenario 3			Original Application Proposed Rates		
March 1 - February 28	**2019/20**	**2020/21**	**2021/22**	**2019/20**	**2020/21**	**2021/22**
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,449.85	$ 1,481.27	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.4%	2.2%	0.0%	1.1%	1.2%
Total Cost	**$ 1,548.08**	**$ 1,554.64**	**$ 1,587.64**	**$ 1,548.08**	**$ 1,564.45**	**$ 1,582.58**
	-2.4%	0.4%	2.1%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,421.65	$ 1,453.07	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.4%	2.2%	0.0%	1.1%	1.2%
Total Cost	**$ 1,515.65**	**$ 1,522.22**	**$ 1,555.21**	**$ 1,515.65**	**$ 1,532.02**	**$ 1,550.15**
	-2.4%	0.4%	2.2%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,749.15	$ 23,242.65	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.4%	2.2%	0.0%	1.1%	1.2%
Total Cost	**$ 26,048.45**	**$ 26,161.52**	**$ 26,729.05**	**$ 26,048.45**	**$ 26,345.02**	**$ 26,650.62**
	0.0%	0.4%	2.2%	0.0%	1.1%	1.2%

Scenario 3 Impact

Composition of Total Energy Charge per kWh by Rate Class - IR 96 Scenario 3	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1432	1.6%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1132	1.6%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1768	1.7%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1145	1.7%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1731	1.6%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0858	1.7%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0684	-0.3%

Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ -	-100.0%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0040	-25.0%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0013	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0001)	-97.3%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0053	89.3%

Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1485	3.3%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1185	3.8%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1821	3.1%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1198	3.8%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1784	3.1%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0911	4.5%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0737	3.2%

* Rate change effective March 1.

Scenario 3 Impact

January 2020 Rate Application
Supplemental Information - 2019, 2020 and 2021 Inputs

Calculation of Rate Base ($)

			Proposed in Original Application		IR 96 Scenario 3		Difference from Proposed	
Components	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 705,485,600	$ 693,668,900	(6,730,200)	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	(2,950,000)	-	(2,950,000)	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,717,700)	(231,746,300)	185,900	187,600
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(23,476,600)	(24,411,500)	1,121,400	1,084,500
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(22,823,300)	(29,525,900)	(3,069,100)	(3,311,300)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	-	3,500	(72,200)	481,600
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-			-	-	-	-
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(1,287,800)	(1,159,600)	4,559,500	3,488,500
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	9,654,500	-	-
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,750,800	6,098,100	(101,600)	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 405,552,900**	**$ 426,972,700**	**$ (7,056,300)**	**$ 1,930,900**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 399,400,128**	**$ 416,262,800**	**$ (3,528,150)**	**$ (2,562,700)**

Calculation of Return on Average Rate Base ($) & (%)

		As Proposed		IR 96 Scenario 3		Difference from Proposed	
	2019 Actual	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 220,689,100	$ 231,143,900	$ (8,433,400)	$ 141,400
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(158,227,200)	(169,389,200)	4,670,000	(52,900)
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	62,448,100	61,740,200	(3,763,400)	88,500
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,386,200)	(26,200,600)	185,900	1,700
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(260,000)	-	-
	(23,587,836)	(31,795,800)	(26,462,300)	(31,609,900)	(26,460,600)	185,900	1,700
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	30,838,200	35,279,600	(3,577,500)	90,200
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(5,649,400)	(6,938,400)	1,092,800	39,800
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 25,188,800	$ 28,341,200	(2,484,700)	130,000
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 399,400,128	$ 416,262,800	(3,528,150)	(2,562,700)
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.31%**	**6.81%**	**-0.56%**	**0.07%**

Scenario 4 Impact

Revenue Requirement ($)						
	Original Application Proposed		IR 96 Scenario 4		Difference from Proposed	
	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 158,227,200	$ 169,389,200	$ (4,670,000)	$ 52,900
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,782,500	12,929,800	(61,900)	75,500
Amortization - Fixed Assets	28,572,100	26,202,300	28,386,200	28,131,500	(185,900)	1,929,200
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900	-	-	-
Amortization - Rate Delay Deferral **	-	-	-	3,015,400	-	3,015,400
Income Tax Expense	6,742,200	6,978,200	6,742,600	6,979,000	400	800
Return on Equity***	14,842,900	15,371,400	14,844,900	15,373,000	2,000	1,600
Total Gross Electric Revenue	**229,122,500**	**231,002,500**	**224,207,100**	**236,077,900**	**(4,915,400)**	**5,075,400**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	102,300	-	1,159,600	-
Other Revenue	(13,425,300)	(13,217,400)	(16,749,300)	(13,292,900)	(3,324,000)	(75,500)
Revenue Requirement to be Collected Through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 204,557,200**	**$ 222,785,000**	**$ (7,079,800)**	**$ 4,999,900**

*   *Excluding Fortis Inc. Costs*

*** Remaining balance of $502,600 will be collected in January & February 2022*

**** Before Disallowable Costs*

Scenario 4 Impact

Impact on Annual Cost March 1 - February 28						
	IR 96 Scenario 4			Original Application Proposed Rates		
March 1 - February 28	**2019/20**	**2020/21**	**2021/22**	**2019/20**	**2020/21**	**2021/22**
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,454.79	$ 1,510.91	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.8%	3.9%	0.0%	1.1%	1.2%
Total Cost	**$ 1,548.08**	**$ 1,559.83**	**$ 1,618.76**	**$ 1,548.08**	**$ 1,564.45**	**$ 1,582.58**
	-2.4%	0.8%	3.8%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,426.59	$ 1,482.71	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.8%	3.9%	0.0%	1.1%	1.2%
Total Cost	**$ 1,515.65**	**$ 1,527.41**	**$ 1,586.33**	**$ 1,515.65**	**$ 1,532.02**	**$ 1,550.15**
	-2.4%	0.8%	3.9%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,828.15	$ 23,716.65	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.8%	3.9%	0.0%	1.1%	1.2%
Total Cost	**$ 26,048.45**	**$ 26,252.37**	**$ 27,274.15**	**$ 26,048.45**	**$ 26,345.02**	**$ 26,650.62**
	0.0%	0.8%	3.9%	0.0%	1.1%	1.2%

Scenario 4 Impact

Composition of Total Energy Charge per kWh by Rate Class - IR 96 Scenario 4	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1470	4.3%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1162	4.3%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1816	4.4%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1176	4.4%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1778	4.4%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0881	4.4%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0702	2.3%
Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ -	-100.0%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0040	-25.0%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0013	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0001)	-97.3%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0053	89.3%
Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1523	6.0%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1215	6.4%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1869	5.8%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1229	6.5%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1831	5.8%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0934	7.1%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0755	5.7%

* Rate change effective March 1.

January 2020 Rate Application
Supplemental Information - 2019, 2020 and 2021 Inputs

Calculation of Rate Base ($)								
			Proposed in Original Application		IR 96 Scenario 4		Difference from Proposed	
Components	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 705,485,600	$ 693,668,900	(6,730,200)	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	(2,950,000)	-	(2,950,000)	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,717,700)	(231,746,300)	185,900	187,600
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(23,476,600)	(24,411,500)	1,121,400	1,084,500
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(23,916,500)	(30,659,600)	(4,162,300)	(4,445,000)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	-	3,500	(72,200)	481,600
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-			3,518,000	502,600	3,518,000	502,600
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(1,287,800)	(1,159,600)	4,559,500	3,488,500
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	7,723,600	-	(1,930,900)
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,750,800	6,098,100	(101,600)	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 407,977,700**	**$ 424,410,700**	**$ (4,631,500)**	**$ (631,100)**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 400,612,528**	**$ 416,194,200**	**$ (2,315,750)**	**$ (2,631,300)**

Calculation of Return on Average Rate Base ($) & (%)							
		As Proposed		IR 96 Scenario 4		Difference from Proposed	
	2019 Actual	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 224,207,100	$ 236,077,900	$ (4,915,400)	$ 5,075,400
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(158,227,200)	(169,389,200)	4,670,000	(52,900)
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	65,966,100	66,674,200	(245,400)	5,022,500
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,386,200)	(28,131,500)	185,900	(1,929,200)
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(3,275,400)	-	(3,015,400)
	(23,587,836)	(31,795,800)	(26,462,300)	(31,609,900)	(31,406,900)	185,900	(4,944,600)
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	34,356,200	35,267,300	(59,500)	77,900
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(6,742,600)	(6,979,000)	(400)	(800)
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 27,613,600	$ 28,288,300	(59,900)	77,100
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 400,612,528	$ 416,194,200	(2,315,750)	(2,631,300)
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.89%**	**6.80%**	**0.02%**	**0.06%**

Scenario Supporting Calculations

Supporting Calculations for Scenario 1

Revised Revenue Shortfall		**2020**	
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900	
Reduction in Other Revenue Forecast		193,543	
Reduction In Operating Expenses:			
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)		
Reduction in Net Energy Costs due to No Change to ECAM Base Rate (Note 2)	(753,655)		
Reductions in Other Operating Expenses	(925,780)		
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)	
Reduction in Depreciation & Interest Expense		(245,100)	
October 2020 YTD Adjustment to WNRA		102,300	
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328	
Total Revenue Shortfall		**$ 3,517,971**	
	Per Month	**2021**	**2022**
Amortized over 14 months	$ 251,284	$ 3,015,404	$ 502,567

Note 1 - Reduction in Net Energy Costs due to lower NPP		**Jan 1 - Dec 31, 2020**	
January Filing, Net Purchased & Produced Energy in kWh	1,450,198,653		
October 2020 YTD Forecast, Net Purchased & Produced Energy in kWh	1,412,690,542		
Lower Forecast NPP from January Filing in kWh	37,508,111		
Existing ECAM Base Rate	$ 91.61		
Reduction in Net Energy Costs due to lower NPP		**$ (3,436,118)**	
Note 2 - Reduction in Net Energy Costs due to No Change to ECAM Base Rate		**Mar 1 - Dec 31, 2020**	
Net Purchased & Produced Energy in kWh		1,177,585,726	
Proposed March 1, 2020 ECAM Base Rate - not approved	92.25		
Existing ECAM Base Rate	91.61	$ (0.64)	
Reduction in Proposed Net Energy Costs due to Lower ECAM Base Rate		**$ (753,655)**	
CTGS Reserve Amortized Over 60 Mos starting in 2021			
		Per Month	**2021-2025 Annual**
CTGS Reserve	$ 9,654,524	$ 160,909	$ 1,930,905

RORA Adjustments & Refund Rate		
RORA Balance 10/31/2020		$ 7,864,663
Forecast Refund for November & December 2020		(779,139)
2019 Hurricane Dorian Deferral Applied to RORA		(3,002,882)
WNRA @ 10/31/2020 (assumes normal HDD for November & December)		1,159,601
ECAM forecast at 12/31/2020		(3,538,669)
2019 EE&C Adjustment		(415,802)
Forecast Balance to be Refunded, 12/31/2020		$ 1,287,772
kWh Sales - Refund 12 mos (Jan-Dec, 2020)		1,384,528,646
Refund Rate		**$ 0.0009**
PEIEC EE&C Plan		
Proposed		$ 3,100,000
Adjustments:		
2019 Component		(415,802)
2020 Component ($573,000-127,447)		(445,553)
Balance to be Recovered Though a Rate Rider		$ 2,238,645
Total kWh (14 months)		1,659,431,460
PEIEC EE&C Plan Rate Rider per kWh		**$ 0.0013**
Provincial Costs Recoverable		
Lepreau/Dal Debt Repayments	$ 476,471	
	14 Months	$ 6,670,594
Total kWh (14 months)		1,659,431,460
Provincial Costs Recoverable Rate Rider per kWh		**$ 0.0040**

Supporting Calculations for Scenario 2

Revised Revenue Shortfall		**2020**	
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900	
Reduction in Other Revenue Forecast		193,543	
Reduction In Operating Expenses:			
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)		
Reduction in Net Energy Costs due to No Change to ECAM Base Rate (Note 2)	(753,655)		
Reductions in Other Operating Expenses	(925,780)		
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)	
Reduction in Depreciation & Interest Expense		(245,100)	
October 2020 YTD Adjustment to WNRA		102,300	
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328	
Not Approved		(3,517,971)	
Total Revenue Shortfall		**$ -**	
	Per Month	**2021**	**2022**
Amortized over 14 months	$ 251,284	$ 3,015,404	$ 502,567

Note 1 - Reduction in Net Energy Costs due to lower NPP		**Jan 1 - Dec 31, 2020**
January Filing, Net Purchased & Produced Energy in kWh	1,450,198,653	
October 2020 YTD Forecast, Net Purchased & Produced Energy in kWh	1,412,690,542	
Lower Forecast NPP from January Filing in kWh	37,508,111	
Existing ECAM Base Rate	$ 91.61	
Reduction in Net Energy Costs due to lower NPP		**$ (3,436,118)**

Note 2 - Reduction in Net Energy Costs due to No Change to ECAM Base Rate		**Mar 1 - Dec 31, 2020**
Net Purchased & Produced Energy in kWh		1,177,585,726
Proposed March 1, 2020 ECAM Base Rate - not approved	92.25	
Existing ECAM Base Rate	91.61	$ (0.64)
Reduction in Proposed Net Energy Costs due to Lower ECAM Base Rate		**$ (753,655)**

CTGS Reserve Amortized Over 60 Mos starting in 2021		**Per Month**	**2021-2025**
CTGS Reserve	$ 9,654,524.00	$ 160,909	$ 1,930,905

RORA Adjustments & Refund Rate		
RORA Balance 10/31/2020		$ 7,864,663
Forecast Refund for November & December 2020		(779,139)
2019 Hurricane Dorian Deferral Applied to RORA		(3,002,882)
WNRA @ 10/31/2020 (assumes normal HDD for November & December)		1,159,601
ECAM		(3,538,669)
2019 EE&C Adjustment		(415,802)
Balance to be refunded		1,287,772
Refund 12 mos (Jan-Dec)		1,384,528,646
Refund Rate		**$ 0.0009**

PEIEC EE&C Plan		
Proposed		$ 3,100,000
Adjustments:		
2019 Component		(415,802)
2020 Component ($573,000-127,447)		(445,553)
Balance to be recovered thru rider		$ 2,238,645
Total kWh (14 months)		1,659,431,460
PEIEC EE&C Plan Rate Rider per kWh		**$ 0.0013**

Provincial Costs Recoverable		
Lepreau/Dal Debt Repayments	$ 476,471	
	14 Months	$ 6,670,594
Total kWh (14 months)		1,659,431,460
Provincial Costs Recoverable Rate Rider per kWh		**$ 0.0040**

Supporting Calculations for Scenario 3

Revised Revenue Shortfall		**2020**	
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900	
Reduction in Other Revenue Forecast		193,543	
Reduction In Operating Expenses:			
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)		
Reduction in Net Energy Costs due to No Change to ECAM Base Rate (Note 2)	(753,655)		
Reductions in Other Operating Expenses	(925,780)		
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)	
Reduction in Depreciation & Interest Expense		(245,100)	
October 2020 YTD Adjustment to WNRA		102,300	
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328	
Not Approved		(3,517,971)	
Total Revenue Shortfall		**$ -**	
	Per Month	**2021**	**2022**
Amortized over 14 months	$ 251,284	$ 3,015,404	$ 502,567

Note 1 - Reduction in Net Energy Costs due to lower NPP		**Jan 1 - Dec 31, 2020**
January Filing, Net Purchased & Produced Energy in kWh	1,450,198,653	
October 2020 YTD Forecast, Net Purchased & Produced Energy in kWh	1,412,690,542	
Lower Forecast NPP from January Filing in kWh	37,508,111	
Existing ECAM Base Rate	$ 91.61	
Reduction in Net Energy Costs due to lower NPP		**$ (3,436,118)**

Note 2 - Reduction in Net Energy Costs due to No Change to ECAM Base Rate		**Mar 1 - Dec 31, 2020**
Net Purchased & Produced Energy in kWh		1,177,585,726
Proposed March 1, 2020 ECAM Base Rate - not approved	92.25	
Existing ECAM Base Rate	91.61	$ (0.64)
Reduction in Proposed Net Energy Costs due to Lower ECAM Base Rate		**$ (753,655)**

CTGS Reserve Deferred		**Per Month**	**2021-2025**
CTGS Reserve	$ 9,654,524	$ -	$ -

RORA Adjustments & Refund Rate	
RORA Balance 10/31/2020	$ 7,864,663
Forecast Refund for November & December 2020	(779,139)
2019 Hurricane Dorian Deferral Applied to RORA	(3,002,882)
ECAM	(3,538,669)
2019 EE&C Adjustment	(415,802)
Balance to be refunded	128,171
Refund 12 mos (Jan-Dec)	1,384,528,646
Refund Rate	**0.0001**

PEIEC EE&C Plan	
Proposed	$ 3,100,000
Adjustments:	
2019 Component	(415,802)
2020 Component ($573,000-127,447)	(445,553)
Balance to be recovered thru rider	$ 2,238,645
Total kWh (14 months)	1,659,431,460
PEIEC EE&C Plan Rate Rider per kWh	**$ 0.0013**

Provincial Costs Recoverable		
Lepreau/Dal Debt Repayments	$ 476,471	
	14 Months	$ 6,670,594
Total kWh (14 months)		1,659,431,460
Provincial Costs Recoverable Rate Rider per kWh		**$ 0.0040**

Supporting Calculations for Scenario 4

Revised Revenue Shortfall		**2020**
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900
Reduction in Other Revenue Forecast		193,543
Reduction In Operating Expenses:		
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)	
Reduction in Net Energy Costs due to No Change to ECAM Base Rate (Note 2)	(753,655)	
Reductions in Other Operating Expenses	(925,780)	
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)
Reduction in Depreciation & Interest Expense		(245,100)
October 2020 YTD Adjustment to WNRA		102,300
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328
Total Revenue Shortfall		**$ 3,517,971**

	Per Month	**2021**	**2022**
Amortized over 14 months	$ 251,284	$ 3,015,404	$ 502,567

Note 1 - Reduction in Net Energy Costs due to lower NPP		**Jan 1 - Dec 31, 2020**
January Filing, Net Purchased & Produced Energy in kWh	1,450,198,653	
October 2020 YTD Forecast, Net Purchased & Produced Energy in kWh	1,412,690,542	
Lower Forecast NPP from January Filing in kWh	37,508,111	
Existing ECAM Base Rate	$ 91.61	
Reduction in Net Energy Costs due to lower NPP		**$ (3,436,118)**

Note 2 - Reduction in Net Energy Costs due to No Change to ECAM Base Rate		**Mar 1 - Dec 31, 2020**
Net Purchased & Produced Energy in kWh		1,177,585,726
Proposed March 1, 2020 ECAM Base Rate - not approved	92.25	
Existing ECAM Base Rate	91.61	$ (0.64)
Reduction in Proposed Net Energy Costs due to Lower ECAM Base Rate		**$ (753,655)**

CTGS Reserve Amortized Over 60 Mos starting in 2021		**Per Month**	**2021-2025**
CTGS Reserve	**$ 9,654,524.00**	**$ 160,909**	**$ 1,930,905**

RORA Adjustments & Refund Rate	
RORA Balance 10/31/2020	$ 7,864,663
Forecast Refund for November & December 2020	(779,139)
2019 Hurricane Dorian Deferral Applied to RORA	(3,002,882)
ECAM	(3,538,669)
2019 EE&C Adjustment	(415,802)
Balance to be refunded	128,171
Refund 12 mos (Jan-Dec)	1,384,528,646
Refund Rate	**0.0001**

PEIEC EE&C Plan	
Proposed	$ 3,100,000
Adjustments:	
2019 Component	(415,802)
2020 Component ($573,000-127,447)	(445,553)
Balance to be recovered thru rider	$ 2,238,645
Total kWh (14 months)	1,659,431,460
PEIEC EE&C Plan Rate Rider per kWh	**$ 0.0013**

Provincial Costs Recoverable		
Lepreau/Dal Debt Repayments	$ 476,471	
	14 Months	$ 6,670,594
Total kWh (14 months)		1,659,431,460
Provincial Costs Recoverable Rate Rider per kWh		**$ 0.0040**

Supporting Calculations for Scenario 5

Revised Revenue Shortfall		**2020**	
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900	
Reduction in Other Revenue Forecast		193,543	
Reduction In Operating Expenses:			
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)		
Reduction in Net Energy Costs due to No Change to ECAM Base Rate (Note 2)	(753,655)		
Reductions in Other Operating Expenses	(925,780)		
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)	
Reduction in Depreciation & Interest Expense		(245,100)	
October 2020 YTD Adjustment to WNRA		102,300	
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328	
Total Revenue Shortfall		**$ 3,517,971**	
	Per Month	**2021**	**2022**
Amortized over 14 months	$ 251,284	$ 3,015,404	$ 502,567

Note 1 - Reduction in Net Energy Costs due to lower NPP		**Jan 1 - Dec 31, 2020**
January Filing, Net Purchased & Produced Energy in kWh	1,450,198,653	
October 2020 YTD Forecast, Net Purchased & Produced Energy in kWh	1,412,690,542	
Lower Forecast NPP from January Filing in kWh	37,508,111	
Existing ECAM Base Rate	$ 91.61	
Reduction in Net Energy Costs due to lower NPP		**$ (3,436,118)**

Note 2 - Reduction in Net Energy Costs due to No Change to ECAM Base Rate		**Mar 1 - Dec 31, 2020**
Net Purchased & Produced Energy in kWh		1,177,585,726
Proposed March 1, 2020 ECAM Base Rate - not approved	92.25	
Existing ECAM Base Rate	91.61	$ (0.64)
Reduction in Proposed Net Energy Costs due to Lower ECAM Base Rate		**$ (753,655)**

CTGS Reserve Deferred			
		Per Month	**2021-2025**
CTGS Reserve	**$ -**	**$ -**	**$ -**

RORA Adjustments & Refund Rate	
RORA Balance 10/31/2020	$ 7,864,663
Forecast Refund for November & December 2020	(779,139)
2019 Hurricane Dorian Deferral Applied to RORA	(3,002,882)
WNRA @ 10/31/2020 (assumes normal HDD for November & December)	1,159,601
ECAM	(3,538,669)
2019 EE&C Adjustment	(415,802)
Balance to be refunded	1,287,772
Refund 12 mos (Jan-Dec)	1,384,528,646
Refund Rate	**$ 0.0009**

PEIEC EE&C Plan	
Proposed	$ 3,100,000
Adjustments:	
2019 Component	(415,802)
2020 Component ($573,000-127,447)	(445,553)
Balance to be recovered thru rider	$ 2,238,645
Total kWh (14 months)	1,659,431,460
PEIEC EE&C Plan Rate Rider per kWh	**$ 0.0013**

Provincial Costs Recoverable		
Lepreau/Dal Debt Repayments	$ 476,471	
	14 Months	$ 6,670,594
Total kWh (14 months)		1,659,431,460
Provincial Costs Recoverable Rate Rider per kWh		**$ 0.0040**

Scenario 5 Impact

Revenue Requirement ($)						
	Original Application Proposed		IR 96 Scenario 5		Difference from Proposed	
	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 158,227,200	$ 169,389,200	$ (4,670,000)	$ 52,900
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,785,200	12,951,500	(59,200)	97,200
Amortization - Fixed Assets	28,572,100	26,202,300	28,386,200	26,200,600	(185,900)	(1,700)
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900		-	-
Amortization - Rate Delay Deferral **	-	-	-	3,015,400	-	3,015,400
Income Tax Expense	6,742,200	6,978,200	6,741,700	6,978,800	(500)	600
Return on Equity***	14,842,900	15,371,400	14,843,000	15,372,700	100	1,300
Total Gross Electric Revenue	**229,122,500**	**231,002,500**	**224,207,000**	**234,168,200**	**(4,915,500)**	**3,165,700**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	102,300	-	1,159,600	-
Other Revenue	(13,425,300)	(13,217,400)	(16,749,300)	(13,279,200)	(3,324,000)	(61,800)
Revenue Requirement to be Collected Through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 204,557,100**	**$ 220,889,000**	**$ (7,079,900)**	**$ 3,103,900**

* *Excluding Fortis Inc. Costs*
** *Remaining balance of $502,600 will be collected in January & February 2022*
*** *Before Disallowable Costs*

Scenario 5 Impact

Impact on Annual Cost March 1 - February 28						
	IR 96 Scenario 5			Original Application Proposed Rates		
March 1 - February 28	**2019/20**	**2020/21**	**2021/22**	**2019/20**	**2020/21**	**2021/22**
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,451.62	$ 1,492.99	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.6%	2.8%	0.0%	1.1%	1.2%
Total Cost	**$ 1,548.08**	**$ 1,556.50**	**$ 1,599.95**	**$ 1,548.08**	**$ 1,564.45**	**$ 1,582.58**
	-2.4%	0.5%	2.8%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,423.42	$ 1,464.79	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.6%	2.9%	0.0%	1.1%	1.2%
Total Cost	**$ 1,515.65**	**$ 1,524.08**	**$ 1,567.51**	**$ 1,515.65**	**$ 1,532.02**	**$ 1,550.15**
	-2.4%	0.6%	2.8%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,780.40	$ 23,446.90	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.6%	2.9%	0.0%	1.1%	1.2%
Total Cost	**$ 26,048.45**	**$ 26,197.46**	**$ 26,963.93**	**$ 26,048.45**	**$ 26,345.02**	**$ 26,650.62**
	0.0%	0.6%	2.9%	0.0%	1.1%	1.2%

Scenario 5 Impact

Composition of Total Energy Charge per kWh by Rate Class - IR 96 Scenario 5							
	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1454	3.2%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1150	3.2%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1797	3.3%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1164	3.4%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1760	3.3%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0872	3.3%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0698	1.7%

Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ -	-100.0%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0040	-25.0%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0013	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0009)	-73.0%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0044	57.1%

Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1498	4.2%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1194	4.6%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1841	4.2%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1208	4.7%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1804	4.2%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0916	5.0%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0742	3.9%

* Rate changes effective March 1.

January 2020 Rate Application
Supplemental Information - 2019, 2020 and 2021 Inputs

Calculation of Rate Base ($)								
			Proposed in Original Application		IR 96 Scenario 5		Difference from Proposed	
Components	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 705,485,600	$ 693,668,900	(6,730,200)	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	(2,950,000)	-	(2,950,000)	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,717,700)	(231,746,300)	185,900	187,600
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(23,476,600)	(24,411,500)	1,121,400	1,084,500
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(23,915,700)	(30,658,700)	(4,161,500)	(4,444,100)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	-	3,500	(72,200)	481,600
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-			3,518,000	502,600	3,518,000	502,600
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(1,287,800)	-	4,559,500	4,648,100
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	9,654,500	-	-
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,750,800	6,098,100	(101,600)	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 407,978,500**	**$ 427,502,100**	**$ (4,630,700)**	**$ 2,460,300**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 400,612,928**	**$ 417,740,300**	**$ (2,315,350)**	**$ (1,085,200)**

Calculation of Return on Average Rate Base ($) & (%)							
		As Proposed		IR 96 Scenario 5		Difference from Proposed	
	2019 Actual	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 224,207,000	$ 234,168,200	$ (4,915,500)	$ 3,165,700
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(158,227,200)	(169,389,200)	4,670,000	(52,900)
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	65,966,000	64,764,500	(245,500)	3,112,800
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,386,200)	(26,200,600)	185,900	1,700
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(3,275,400)	-	(3,015,400)
	(23,587,836)	(31,795,800)	(26,462,300)	(31,609,900)	(29,476,000)	185,900	(3,013,700)
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	34,356,100	35,288,500	(59,600)	99,100
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(6,741,700)	(6,978,800)	500	(600)
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 27,614,400	$ 28,309,700	(59,100)	98,500
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 400,612,928	$ 417,740,300	(2,315,350)	(1,085,200)
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.89%**	**6.78%**	**0.02%**	**0.04%**