MARITIME ELECTRIC
A FORTIS COMPANY

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FEB 05 2016
The Island Regulatory and Appeals Commission

February 5, 2016

Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

Pursuant to Order UE16-01, please find enclosed 10 copies of Maritime Electric's amended and updated evidence in support of the 2016 General Rate Agreement seeking approval of a revised schedule of rates, tolls and charges to be effective March 1, 2016. An electronic copy will be forwarded shortly.

If you require further information, please do not hesitate to contact me at (902) 629-3667.

Yours truly,

MARITIME ELECTRIC

S. D. Loggie
Vice President,
Finance & Chief Financial Officer

SLD08
Encl. as noted

Maritime Electric

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental to such an order.

AND IN THE MATTER of Section 26 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and Section 12 of the Island Regulatory and Appeals Commission Act (R.S.P.E.I. 1988, Cap. I-11) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission with respect to input factors for the period between January 1, 2016 and February 29, 2016 and to establish rates of depreciation with respect to the Company's several classes of property for the period beginning January 1, 2016 and for certain approvals incidental to such an order.

Date: February 5, 2016

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C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

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AND APPEALS COMMISSION

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AFFIDAVIT

We, Frederick James O'Brien, of Alberton, in Prince County, Steven David Loggie, John David Gaudet and Angus Sumner Orford of Charlottetown, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

1. We are the President and Chief Executive Officer, Vice President, Finance and Chief Financial Officer, Vice President, Corporate Planning and Energy Supply and Vice President, Customer Service for Maritime Electric Company, Limited ("Maritime Electric" or the "Company") respectively and as such have personal knowledge of the matters deposed to herein, except where noted, in which case we rely upon the information of others and in which case we verily believe such information to be true.

2. Maritime Electric is a public utility subject to the provisions of the Electric Power Act ("EPA") engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

3. We prepared or supervised the preparation of the evidence and to the best of our knowledge and belief the evidence is true in substance and in fact. A copy of the evidence is attached to this our Affidavit, and is collectively attached as Exhibit "A", contained at Tabs 3 through 11 inclusive.

4. The evidence found at Tab 3 (the "Overview") contains a brief overview of past related filings by the Company to the Island Regulatory and Appeals Commission ("Commission") and the purpose of the attached filing.

5. The evidence found at Tab 4 (the "Background") contains information with respect to events culminating in the filing with the Commission of the 2016 General Rate Agreement by the Company on January 29, 2016.

6. The evidence found at Tab 5 (the "Comparison Between General Rate Application and 2016 General Rate Agreement") provides a summary comparison of the inputs between the General Rate Application filing of October 28, 2015 and the 2016 General Rate Agreement filing of January 29, 2016.

7. The evidence found at Tab 6 (the "Reconciliation of changes to 2016 Revenue Requirement") contains information that reconciles the changes in the 2016 Revenue Requirement presented in the General Rate Application and that presented in the 2016 General Rate Agreement.

8. The evidence found at Tab 7 (the "Changes to Customer Electricity Costs 2016") outlines the changes in the impact on customer electricity costs proposed in the 2016 General Rate Agreement versus the customer electricity costs proposed in the General Rate Application.

9. The evidence found at Tab 8 (the "Supplemental Information - Financial Inputs") provides supplemental information on the proposed financial inputs contained in the Agreement for the years 2016, 2017 and 2018.

10. The evidence found in Tab 9 (the "Summary") provides a summary of the matters in this filing.

11. Tab 10 contains a Proposed Order of the Commission with related appendices based on the 2016 General Rate Agreement and the evidence in this filing.

12. The evidence found at Tab 11 (the "Appendices") contains Appendices A through E inclusive which are referred to in the evidence.

SWORN TO SEVERALLY at
Charlottetown, Prince Edward
Island, the 5th day of February, 2016.
Before me:

Frederick J. O'Brien

Steven D. Loggie

John D. Gaudet

Angus S. Orford

A Commissioner for taking affidavits
in the Supreme Court of Prince Edward Island.

3.0 OVERVIEW

On October 28, 2015 Maritime Electric filed a General Rate Application (the "Application") with the Commission. The Application provided evidence in support of rates, tolls and charges for service to customers for a one year period commencing March 1, 2016.

In support of the Application, the Company provided expert evidence with respect to the appropriate return on average common equity ("ROE") that would be appropriate for the Company as well as expert evidence with respect to cost allocation matters. The Company had also pre-filed the 2014 Depreciation Study Application (Docket UE21603), the 2015 – 2020 Demand Side Management Plan Application (Docket UE21406) and the 2016 Capital Budget (Docket UE20724). On November 3, 2015 the Commission issued Order UE15-01 providing disposition with respect to the 2016 Capital Budget Application and Order UE15-02 that addressed the Company's Demand Side Management Plan Application.

On January 29, 2016 Maritime Electric and the Province of PEI jointly filed with the Commission a 2016 General Rate Agreement and covering Minutes of Settlement, (the "Agreement"), which addressed matters raised in the Application and the 2014 Deprecation Study Application, as well as other matters related to electric service on PEI. A copy of the Agreement is included in Appendix A of this evidence.

The Agreement amends the Company's initial filing of its Application and, in particular, amends the proposed rates, tolls and changes for electric service effective March 1, 2016 with further amendments on March 1, 2017 and March 1, 2018.

The Company seeks the Commission’s approval of the Agreement and the new electricity rates for the period March 1, 2016 to February 28, 2019 as outlined in Appendix 1 of the Agreement.

Pursuant to Order UE16-01, this filing provides further information to the Commission with respect to the filing of the Agreement including background information, a comparison between the Application and the Agreement (including a reconciliation of the changes in the Company’s 2016 revenue requirement between the two documents), comparative analysis of how customer electricity costs for 2016 are impacted under the terms of these two documents and supplemental, updated information with respect to key financial inputs proposed in the Agreement for the years 2016, 2017 and 2018.

4.0 BACKGROUND

Subsequent to the Company's filing of the Application with the Commission on October 28, 2015 the Company and the Government of PEI ("Government") undertook discussions to explore i) a collaborative approach to secure least cost reliable sources of electric energy and related capacity at stable and predictable rates; ii) how the parties might work collaboratively on a new provincial energy strategy and on innovative and effective Demand Side Management ("DSM") policies to improve energy efficiency and reduce energy consumption in the Province; and iii) specific matters on issues in the Application and the 2014 Depreciation Study Application the parties mutually agreed upon.

Maritime Electric and Government did reach agreement with respect to matters within the Application and 2014 Depreciation Study Application and on January 29, 2016 filed, with the Commission, the Agreement entered into by both parties.

The terms of the Agreement differ from the relief sought by Maritime Electric in the Application and 2014 Depreciation Study Application as discussed herein.

This document sets out the differences between the Application and the Agreement (including a reconciliation of changes in the Company's 2016 revenue requirement presented in the two documents), a comparative analysis of how customer electricity costs for 2016 are impacted under the two documents and supplemental, updated information with respect to the key financial inputs proposed in the Agreement for the years 2016, 2017 and 2018.

5.0 COMPARISON BETWEEN GENERAL RATE APPLICATION AND 2016 GENERAL RATE AGREEMENT

5.1 Differences Between Application and Agreement

The Agreement and the associated Appendices filed with the Commission on January 29, 2016 differs from the Application in a number of areas. The following table summarizes the key differences between the two filings.

	General Rate Application	2016 Rate Agreement
Proposed Rate Setting Term	1 Year (March 1, 2016 – February 28, 2017)	3 Years (March 1, 2016 – February 28, 2019)
Return on Average Common Equity - 2016	9.70% for setting revenue requirement within an allowed range of 9.50% – 9.90%	9.35%
Average Common Equity	2016 – 40.5%	2016 – 40.9%; 2017 – 40.0%; 2018 – 40.0%
Regulatory Costs - 2016	$1,009,300	$802,300
Financing Costs - 2016	$12,705,600	$12,388,100
Cost Allocation Proposal	Residential Second Block/GS1	Pending Further Detailed Study
Customer Electricity Costs	2.5% (Typical Customer)	2.3% per year (Typical Customer)
Rate of Return Adjustment (RORA) Refund Period	2 years	3 years

- Return on Average Common Equity ("ROE")

  The Company and the Province have agreed to an allowed ROE of 9.35 per cent for each year of the three year agreement which is approximately 0.35 per cent lower than the rate proposed in the Application for purposes of setting revenue requirement. The Company believes that a three-year annual ROE of 9.35 per cent is still within the range of reasonableness and is supported by the evidence filed in Section 12 of the Application.

  In particular, the 9.35 per cent ROE is within the range of the Allowed and Earned ROEs presented in Schedule 12-9 of the Application evidence for both 2014 and 2015 and continues to reflect the Commission's past recognition of a higher risk premium in comparison to other Atlantic Canadian investor-owned utilities.

- Average Common Equity

  The Company is forecasting a year end common equity percentage of 40 per cent in each of the three years 2016 – 2018. The average common equity of 40.9 per cent under the Agreement is higher than the Application filing because the 2015 actual year end result of 41.9 per cent was used in the Agreement which is higher than the 2015 forecast of 41.0 per cent used in the Application. The difference in actual 2015 year end equity levels, versus the 2015 forecast utilized in the Application, is due to lower than forecast year end debt and liability levels. Therefore, using the actual results for 2015 and a forecast 40.0 per cent year end common equity for 2016 results in a somewhat higher average common equity percentage of 40.9 per cent in 2016 under the Agreement. In accordance with Section 12.1 of the EPA effective January 1, 2017 the Company is forecasting average common equity to be 40.0 per cent in 2017 and 2018.

- Regulatory Costs

  Forecast regulatory costs were reduced by $207,000 from the Application to reflect the expected savings associated with a shorter Regulatory hearing process including lower legal and other professional fees. These reductions were also factored into the inputs established for 2017 and 2018.

- Financing Costs

  Improved forecast cash flows arising from 2015 actual results as well as lower forecast income tax installments have reduced forecast financing costs for 2016.

- Cost Allocation Proposal Regarding Residential Second Block

  The Application proposal to increase the residential second block threshold to 3,000 kWh effective March 1, 2016, 3,800 kWh effective March 1, 2017 and 5,000 kWh effective March 1, 2018 and the related offsetting adjustments to the General Service rate class are proposed not to be implemented under the Agreement. During the Agreement term, the Company intends to consult with stakeholders and undertake a rate design study to determine the appropriate rate class for all or some farms, file an updated Cost Allocation Study using 2017 financial data and determine appropriate rates effective March 1, 2019.

- Customer Electricity Costs

  As a result of the changes to the inputs noted in this filing, the projected annual increase in a typical customer's electricity costs in each rate class is forecast to be 2.3 per cent per year as compared to the Application forecast of 2.5 per cent in 2016.

- Rate of Return Adjustment ("RORA") Refund Period

  The RORA refund period is extended under the Agreement to three years as compared to the proposed two year period under the Application. The intent of this approach is consistent with that of the Application in that utilizing a three year refund period will also serve to smooth the impact on customers' electricity costs over the Agreement term and assist in providing stable and predictable rate adjustments during the Agreement. Further details on the RORA balance and refund can be found in Section 8 of this evidence.

5.2 Proposals Common to the Application and the Agreement

As discussed in 5.1 above, the terms of the Agreement primarily differ from the proposals in the Application in the areas of the setting the return on average common equity and in the Agreement's proposed deferral of changes to the Residential second block rate structure.

Aside from these two areas, other proposals set out in the Application and included in the Application's Proposed Order (Section 17 of the Application) remain unchanged and the Company continues to seek the Commission's approval of the following:

- The Energy Cost Adjustment Mechanism ("ECAM") formula implemented during the PEI Energy Accord (and as detailed in Appendix 3 of the Application) shall continue effective March 1, 2016 with the base rate set as per Appendix 2 of the Agreement;

- The Company will refund the RORA deferral accumulated to December 31, 2015 to customers (except over a 3 year period) at rates as per Appendix 2 of the Agreement;

- The establishment of a Weather Normalization Reserve effective January 1, 2016;

- The adoption of the proposals in the Company's filing (UE21603) with respect to the 2014 Depreciation Study Application;

- The undertaking of a Rate Design Study to determine the appropriate rate class for some or all farms. The Application had proposed a filing date with the Commission of April 30, 2017 but given that customers' rates are now proposed to be set until February 28, 2019 the date for filing this study is proposed to be April 30, 2018 which will allow the most current cost allocation and customer data to be utilized;

- General Service II customers will adopt the rate structure of General Service I customers effective March 1, 2016;
- The Company will prepare and file with the Commission a Point Lepreau Classification Study by April 30, 2017;
- The Company will file an updated Cost Allocation Study based on 2017 financial results by June 30, 2018;
- The interim rate classes for LED Street and Area Lights (reference Order UE14-01) are approved for inclusion in the Company's rates; and
- All non-LED Street and Area Light classes currently approved would be closed where comparable LED lights have been approved by the Commission.

The Proposed Order in Tab 10 provides a complete summary of all the proposals from the Agreement for which Commission approval is sought.

6.0 RECONCILIATION OF CHANGES TO 2016 REVENUE REQUIREMENT

Schedule 6-1 outlines the changes between the 2016 revenue requirement in Maritime Electric's Application submitted to the Commission on October 28, 2015 and the revenue requirement reflected in Appendix 2 of the Agreement.

SCHEDULE 6-1			
Revenue Requirement ($)			
	2016 Agreement Forecast	**2016 Application Forecast**	**Difference**
Operating Expenses (Net of ECAM)*	$ 136,249,800	$ 136,456,800	$ (207,000)
Interest Expense (including amortization of Debt Issue Costs)	12,388,000	12,705,600	(317,600)
Amortization - Fixed Assets	21,045,600	21,031,900	13,700
Amortization - DSM Costs	-	-	-
Amortization - Lepreau Writedown	93,400	93,400	-
Income Tax Expense	5,976,200	6,210,500	(234,300)
Return on Average Rate Base**	12,934,300	13,442,600	(508,300)
Total	$ 188,687,300	$ 189,940,800	$ (1,253,500)

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

Overall, forecast 2016 revenue requirement under the Agreement decreased by $1,253,500 from the Application. Forecast 2016 operating expenses were reduced by $207,000 as a result of expected savings in regulatory costs under the Agreement. Forecast interest expenses were reduced by $317,500 in the Agreement as a result of improved cash flows arising from 2015 actual results and 2016 forecast cash flows as well as lower forecast income tax installments. Forecast amortization increased slightly by $13,700 as a result of changes in the actual 2015 capital budget expenditures compared to the 2015 forecast Application expenditures. Forecast income tax expense was reduced by $234,300 as a result of reduced taxable income under the Agreement caused by the lower

ROE. Finally, forecast Return on Average Rate Base was reduced by $508,400 as a result of the reduced ROE from 9.7 per cent in the Application to 9.35 per cent in the Agreement.

7.0 CHANGES TO CUSTOMER ELECTRICITY COSTS - 2016

The reduction of the 2016 Revenue Requirement highlighted previously in Section 6 has the direct impact of reducing customer rates through the Basic Energy Charge component. There are other components of customer rates that impact the overall change in customers' electricity costs. These components, and their impact on customers' electricity costs in the Agreement as compared to the Application, are as follows:

- The fixed monthly service charge is not proposed to change under the Agreement, nor was it proposed to change under the Application.
- The ECAM charge is proposed to decrease by $0.00034/kWh from $0.00240/kWh in the Application to $0.00206/kWh in the Agreement as a result of the lower ECAM receivable from customers at the end of 2015 than forecast in the Application.
- The Provincial Costs Recoverable and the Cable Contingency Fund components both remain unchanged in the Agreement as compared with the Application.
- The RORA rebate to customers for 2016 is $0.00123/kWh lower in the Agreement ($0.00410/kWh) than in the Application ($0.00533/kWh). While the RORA balance payable to customers at December 31, 2015 was higher than forecast in the Application at the end of 2015, the higher balance is proposed to be refunded over three years in the Agreement versus the two years proposed in the Application.

Schedule 7-1 compares the changes in the components of the estimated cost for a rural residential customer consuming 650 kWh per month (7,800 kWh per year) in the Agreement versus the Application.

SCHEDULE 7-1				
Annual Cost for Rural Residential Customer (650 kWh per Month/7,800 kWh per Year)				
	2015 Actual	**2016 Agreement Forecast**	**2016 Application Forecast**	**Difference**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ -
Basic Energy Charge	1,034.28	1,029.60	1,038.96	(9.36)
ECAM Charge	(46.44)	16.06	18.75	(2.69)
Provincial Costs Recoverable	41.81	41.81	41.81	-
Cable Contingency Fund	2.11	2.11	2.11	-
RORA	(5.52)	(31.96)	(41.55)	9.59
Sub-total	1,349.28	1,380.66	1,383.12	(2.46)
HST	188.90	193.29	193.64	(0.35)
Total Annual Cost	**$ 1,538.18**	**$ 1,573.95**	**$ 1,576.76**	**$ (2.81)**
Percentage Annual Increase (Decrease) (%)	**2.2%**	**2.3%**	**2.5%**	**-0.2%**

The annual cost of the above Residential customer will see an increase of 2.3 per cent under the Agreement. This is 0.2 per cent per year lower than was proposed in the Application. The proposed adjustments to Residential rate class rates apply only to per the kWh energy charge and are not applied to the fixed monthly service charge. As a result, the impact on annual electricity costs for residential customers will vary from customer to customer based on their monthly electricity consumption level.

For a typical General Service customer with a monthly consumption and demand profile of 10,000 kWh and 50 kW respectively (120,000 kWh/600 kW per year), the estimated annual increase in electricity costs is shown in Schedule 7-2 below.

SCHEDULE 7-2
Annual Cost for General Service Customer
(10,000 kWh/50 KW per Month/120,000 kWh/600 KW per Year)

Annual Cost $	2015 Actual	2016 Agreement Forecast	2016 Application Forecast	Difference
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ -
Demand Charge	4,834.80	4,834.80	5,061.60	(226.80)
Basic Energy Charge	16,164.00	16,092.00	16,050.00	42.00
ECAM Charge	(714.41)	247.01	288.52	(41.51)
Provincial Costs Recoverable	643.20	643.20	643.20	-
Cable Contingency Fund	32.40	32.40	32.40	-
RORA	(84.87)	(491.68)	(639.17)	147.49
Sub-total	$ 21,169.96	$ 21,652.57	$ 21,731.39	$ (78.82)
HST	2,963.79	3,031.36	3,042.39	(11.03)
Total Annual Cost	**$ 24,133.75**	**$ 24,683.93**	**$ 24,773.78**	**$ (89.85)**
Percentage Annual Increase (Decrease) (%)	**2.2%**	**2.3%**	**2.7%***	**-0.4%**

* *The 2.7 per cent increase in the Application reflects certain proposed rate adjustments to the General Service class, particularly an increase in the demand charge, proposed as a result of the findings in the Cost Allocation Study. Without these class specific adjustments, the increase for a typical General Service customer in the Application would have been 2.5 per cent.*

The above General Service customer will see an increase in electricity costs of approximately 2.3 per cent under the Agreement, a decrease of 0.4 per cent annually under the Agreement compared to the Application.

Typical customers in the Small and Large Industrial rate classes will also experience an increase in electricity costs of approximately 2.3 per cent. Again, the level of consumption of an individual customer will determine whether the increase in electricity costs are higher or lower than that of a typical customer.

8.0 SUPPLEMENTAL INFORMATION – FINANCIAL INPUTS

As discussed in the previous sections, a number of financial inputs for 2016 have changed from the Application as a result of the terms of the Agreement. In addition, the time period covered by the Agreement is extended for two years beyond that which was contemplated in the Application. Updated financial inputs evidence has been provided in Appendix B. This Appendix provides the same schedules that were provided as evidence in the Application updated for the changes to 2016 inputs and expanded to include the financial inputs for 2017 and 2018 under the Agreement. The 2015 actual results are also reflected in these schedules.

The 2016, 2017 and 2018 financial inputs represent the Company's estimated costs to continue to provide a high level of service over this three year period. The following should be noted with respect to the 2016-2018 financial inputs included in Appendix B:

a. Cable Interconnection Costs

The Company's portion of the estimated cable interconnection project ("Project") costs including the repayment to the Province of Project costs (net of Federal funding) and estimated incremental transmission costs in New Brunswick associated with the Project, are included in energy supply costs (see Schedule 8-3 in Appendix B). Repayment to the Province is forecast to commence March 1, 2017 and the incremental costs associated with New Brunswick transmission are forecast to commence July 1, 2017. The total Open Access Transmission Tariff ("OATT") costs and OATT revenue associated with the Project (including the portion of costs attributed to other stakeholders utilizing and paying a portion of the costs of the Project) are included in Schedules 9-2 and 15-5 in Appendix B.

b. Combustion Turbine #4 (“CT4”)

On January 29, 2016, the Company advised the Commission that it has the ability to procure access to an additional 50 MW of firm transmission capacity and accordingly withdrew its CT4 Application (Docket UE #20723) and this withdrawal was accepted by the Commission. Accordingly, the Company has not included any forecast costs associated with this project during the 2016-2018 period.

c. Demand Side Management (“DSM”) Plan

On November 3, 2015, the Commission issued Order UE15-02 with respect to the Company’s DSM Application filed June 3, 2015. The Commission approved annual expenditures of $167,500, commencing in 2016, with respect to public outreach and education. Other aspects of the DSM Application were not approved. The Commission indicated in the Order it will issue a new Order on the matter in due course.

Recognizing that a new DSM plan is likely to be approved later in 2016, the Company has maintained the budgeted provisions for DSM Project expenditures and related annual amortization of those project expenditures as was presented in the Company’s DSM Application.

The Agreement proposes that the DSM Application, as well as the OATT Application (with an interim tariff rate established under Order UE08-03) are subject to further regulatory oversight during the term of the Agreement.

9.0 SUMMARY

The Agreement jointly filed by Maritime Electric and the Province of PEI with the Commission on January 29, 2016 addresses matters raised in both the Application and the 2014 Depreciation Study Application, as well as other matters related to electric service on PEI. The terms of the Agreement amend the relief sought previously and, as a result, amendments to change the rates, tolls and charges for electric service as per Appendix 1 of the Agreement are proposed.

As a result of the key changes discussed in Section 5 of the evidence, the Agreement provides for three years of stable and predictable adjustments to customer electricity costs resulting in annual increases of 2.3 per cent for the typical customer in each class. This represents a 0.2 per cent reduction for the three years as compared to the 2.5 per cent increase proposed in the Application.

Schedules 9-1 and 9-2 show the forecast annual cost for a typical Residential and General Service customer respectively over the three year term of the Agreement.

SCHEDULE 9-1				
Annual Cost for Rural Residential Customer (650 kWh per Month/7,800 kWh per Year)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 323.04
Basic Energy Charge	1,034.28	1,029.60	1,072.50	1,099.02
ECAM Charge	(46.44)	16.06	9.26	4.48
Provincial Costs Recoverable	41.81	41.81	41.81	41.81
Cable Contingency Fund	2.11	2.11	2.11	2.11
RORA	(5.52)	(31.96)	(36.91)	(26.87)
Sub-total	$ 1,349.28	$ 1,380.66	$ 1,411.81	$ 1,443.59
HST	188.90	193.29	197.65	202.10
Total Annual Cost	**$ 1,538.18**	**$ 1,573.95**	**$ 1,609.46**	**$ 1,645.69**
Percentage Annual Increase (%)	**2.2%**	**2.3%**	**2.3%**	**2.3%**

SCHEDULE 9-2				
Annual Cost for General Service Customer (10,000 kWh/50 KW per Month/120,000 kWh/600 KW per Year)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80	4,834.80	4,834.80
Basic Energy Charge	16,164.00	16,092.00	16,764.00	17,190.00
ECAM Charge	(714.41)	247.01	142.53	68.97
Provincial Costs Recoverable	643.20	643.20	643.20	643.20
Cable Contingency Fund	32.40	32.40	32.40	32.40
RORA	(84.87)	(491.68)	(567.81)	(413.42)
Sub-total	$ 21,169.96	$ 21,652.57	$ 22,143.96	$ 22,650.79
HST	2,963.79	3,031.36	3,100.15	3,171.11
Total Annual Cost	**$ 24,133.75**	**$ 24,683.93**	**$ 25,244.11**	**$ 25,821.90**
Percentage Annual Increase (%)	**2.2%**	**2.3%**	**2.3%**	**2.3%**

In accordance with the terms of the Agreement, the Company seeks the Commission’s approval of the Agreement including the proposed rates, tolls and charges for the period March 1, 2016 to February 28, 2019, as detailed in Appendix 1 of the Agreement, as well as approval of other matters addressed in the Agreement and outlined in the Proposed Order in Section 10.

Also attached in this filing, in support of the proposal for new electricity rates for the 3 year period, is a Schedule of Basic Fees, Rates and Charges (Appendix C), revised Company Financial Statements (Appendix D) and revised Monthly ECAM Calculations covering the period January 1, 2016 to December 31, 2018 (Appendix E).

10.0 PROPOSED ORDER

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY

AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental to such an order.

AND IN THE MATTER of Section 26 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E- 4) and Section 12 of the Island Regulatory and Appeals Commission Act (R.S.P.E.I. 1988, Cap. I-11) and IN THE MATTER of the Application of Maritime Electric Company, Limited for an order of the Commission with respect to input factors for the period between January 1, 2016 and February 29, 2016 and to establish rates of depreciation with respect to the Company's several classes of property for the period beginning January 1, 2016 and for certain approvals incidental to such an order.

UPON receiving an Application by Maritime Electric Company, Limited (the "Company") for approval of proposed amendments to its rates, tolls and charges and certain approvals incidental to such an order ("GRA");

AND UPON receiving an Application by the Company with respect to input factors for the period between January 1, 2016 and February 29, 2016 and to establish rates of depreciation with respect to the Company's several classes of property ("Depreciation Application");

AND UPON considering the GRA and Depreciation Application (collectively the "Applications");

AND UPON considering the Evidence of the Company, responses to interrogatories and comments received with respect to the Applications;

AND WHEREAS on December 2, 2015, *An Act to Amend the Electric Power Act*, S.P.E.I. 2015, c. 25, received Royal Assent in the Legislative Assembly ("Amending Act").

AND WHEREAS the *Amending Act*, among other things, includes the repeal of the current Section 12.1 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4 ("Electric Power Act"), and substitution of the following, to be effective January 1, 2017:

> *12.1 Maritime Electric Company, Limited shall, as determined in accordance with generally accepted accounting principles,*
>
> *(a) maintain at all times not less than 35 per cent of its capital invested in the power system in the form of common equity; and*

(b) ensure that, for the year, not more than 40 per cent of its capital is invested in the power system in the form of common equity.

AND UPON it appearing that the Company has entered into a Memorandum of Understanding ("MOU") with the Province of Prince Edward Island ("Province") in respect of a project to upgrade the electrical power interconnection between Prince Edward Island and New Brunswick ("Interconnection Project") and has since issued a request for proposals ("RFP") with respect to the Interconnection Project;

AND WHEREAS the Company and the Province have entered into an agreement that proposes a resolution with respect to the relief sought by the Company in the Applications and cost recovery of the Company's proportionate share of such costs in relation to the Interconnection Project ("2016 General Rate Agreement" or "Agreement");

AND WHEREAS the Commission published notice with respect to the Agreement and considered responses from the public with respect to the terms of the Agreement;

AND WHEREAS the Province is in the process of developing a new provincial energy strategy to assist with short and long term policies, programs and approaches to energy and sustainability;

AND UPON it appearing that the proposed resolution set out in the Agreement is a reasonable, publicly justifiable and non-discriminatory resolution;

NOW THEREFORE for the reasons given in the annexed Reasons for Order;
IT IS ORDERED THAT

1. The Energy Cost Adjustment Mechanism ("ECAM") formula implemented during the PEI Energy Accord as detailed in Appendix 3 shall continue effective March 1, 2016 until otherwise ordered by the Commission.

2. The base rate per kWh used in the ECAM be set as follows:

	Current	**March 1, 2016**	**March 1, 2017**	**March 1, 2018**
ECAM Base Rate per kWh ($)	0.08760	0.08605	0.08988	0.09161

3. The Company shall prepare an updated proposal on ECAM rebasing for inclusion in its next rate application.

4. The Company shall apply the rates, tolls and charges as set out in Appendix 1 for the period March 1, 2016 to February 28, 2019, which rates, tolls and charges are based upon the forecasted values and input factors set out in Appendix 2, and such other forecasted values and input factors as may be agreed to by the parties and approved by the Commission. For greater certainty:

   a. the Company shall be entitled to collect the revenue requirement set out in Appendix 2 in order to apply the schedule of rates, tolls and charges set out in Appendix 1;

   b. the cost recovery of the Interconnection Project costs shall be as set out in Appendix 2 for the period March 1, 2016 to February 28, 2019, and thereafter as ordered by the Commission; and

   c. the cost recovery of the Company's share of the Interconnection Project costs set out in Appendix 2 shall be included as a component of the ECAM.

5. Where the cumulative amount refunded to customers on a per kWh basis through the Rate of Return Adjustment ("RORA") account, as set out in Appendix 2, exceeds or is less than the balance in the RORA account on the Company's audited balance sheet at December 31, 2015, the Company shall recover or refund such net amount from or to customers over a reasonable period commencing March 1, 2019 as further directed by the Commission.

6. In the event that the Company's Return on Average Common Equity exceeds the return on average common equity as set out in Appendix 2, the Company shall return to its customers that portion of its earnings which exceed the return on average common equity set out in Appendix 2 commencing March 1, 2019 as directed by the Commission.

7. A 9.35 per cent Return on Average Common Equity is approved for the years 2016 through 2018.

8. The Company's capital invested in the power system for the purposes of applying the provisions of the *Amending Act* shall be based upon the Company's average capital invested in the power system for the year ("Average Annual Capital Investment"), calculated by using the Company's equity levels at the beginning and end of a given year.

9. The provisions of the *Amending Act* establishing the Company's maximum Average Annual Capital Investment for a given year shall be determined to be for the purpose of calculating the Company's maximum allowable earnings. For the purpose of calculating the Company's earnings as an input factor following January 1, 2017, the Company's maximum allowable earnings shall be based upon a Return on Average Common Equity of 9.35 per cent, or as further ordered by the Commission, and a forecast Average Annual Capital Investment of Forty Percent (40%).

10. The Weather Normalization Mechanism and Reserve account as described in the evidence and Appendix 4 are approved for adoption as of January 1, 2016.

11. The Company shall undertake a Rate Design Study to determine the appropriate rate class for all or some farms currently included in the Residential rate class. The Company shall, as part of this process, consult with applicable stakeholders. The Study shall be filed with the Commission by no later than April 30, 2018.

12. General Service II customers shall adopt the rate structure of General Service I customers effective March 1, 2016.

13. The Company shall prepare and file with the Commission a Point Lepreau Cost Allocation Classification Study by April 30, 2017.

14. The Company shall file an updated Cost Allocation Study based on 2017 financial results by June 30, 2018.

15. The interim rate classes for LED Street and Area Lights approved by the Commission in Order UE14-01 dated January 15, 2014 are approved for inclusion in the Company's rates.

16. All non-LED Street and Area Light classes currently approved are hereby closed to new additions where comparable LED Street and Area Light rate classes have been approved by the Commission.

17. The Company shall adopt depreciation rates calculated as of January 1, 2016, as proposed in the Gannett Fleming 2014 Depreciation Study, and as outlined in Appendix 5 ("Depreciation Rates"). These Depreciation Rates shall remain in effect until February 28, 2019 or varied by the Commission.

18. The Company shall record and incorporate into Depreciation Rates the recommended amortization of the accumulated reserve variance associated with the Charlottetown Thermal Generating Station commencing in 2016 and as outlined in Appendix 6.

19. The Company shall file a Decommissioning Study with respect to the Charlottetown Thermal Generating Station with the Commission no later than June 30, 2018.

20. Order UE08-07 is varied to indicate that the Company shall file an updated Depreciation Study with the Commission no later than June 30, 2018, based on financial results to December 31, 2017. The filing shall include any proposed changes in depreciation rates to ensure that the accumulated reserve variance for all classes of property are addressed prudently, and over a reasonable period of time, and that the results of the Decommissioning Study in 19 above are incorporated into a prudent plan to ensure an adequate future site removal provision is provided for at the Charlottetown Thermal Generating Station.

DATED at Charlottetown this ____ day of ____, 2016

BY THE COMMISSION:

____

__________________, Chair

____

__________________, Commissioner

____

__________________, Commissioner

____

__________________, Commissioner

Maritime Electric Company, Limited
Schedule of Rates

Rate Code		March 1, 2016	March 1, 2017	March 1, 2018
110	**Residential Urban**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance kWh	$ 0.1079	$ 0.1108	$ 0.1142
130	**Residential Rural**			
	Service Charge	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance kWh	$ 0.1079	$ 0.1108	$ 0.1142
131	**Residential Seasonal**			
	Service Charge	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance of kWh	$ 0.1079	$ 0.1108	$ 0.1142
133	**Residential Seasonal Option**			
	Service Charge	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance of kWh	$ 0.1079	$ 0.1108	$ 0.1142
232	**General Service I**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1664	$ 0.1717	$ 0.1767
	Energy Charge per kWh for balance of kWh	$ 0.1090	$ 0.1119	$ 0.1154
233	**General Service I - Seasonal Operators Option**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1664	$ 0.1717	$ 0.1767
	Energy Charge per kWh for balance of kWh	$ 0.1090	$ 0.1119	$ 0.1154
320	**Small Industrial**			
	Demand Charge - per kW	$ 7.46	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1630	$ 0.1682	$ 0.1731
	Energy Charge per kWh for balance of kWh	$ 0.0826	$ 0.0844	$ 0.0872
310	**Large Industrial**			
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0675	$ 0.0694	$ 0.0714
340	**Long Term Contract** (Currently no customers in this rate category)			
	Demand Charge per kW	$ 15.51	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.0911	$ 0.0933	$ 0.0963
330	**Short Term Contract** (Currently no customers in this rate category)			
	Demand Charge - per kW	$ 16.79	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.0929	$ 0.0951	$ 0.0981
	Energy Charge per kWh for balance of kWh in the month	$ 0.0773	$ 0.0789	$ 0.0814

Maritime Electric Company, Limited
Schedule of Rates

	Rate Code	Lamp Wattage	Type		Annual kWh	Monthly kWh	March 1, 2016	March 1, 2017	March 1, 2018
	619	43	LED	St Lights - Rented	176	15	$ 11.53	$ 11.80	$ 12.07
*	620	200	HPS	St Lights - Rented	1033	86	$ 33.15	$ 33.91	$ 34.69
	625	50	LED	St Lights - Rented	205	17	$ 11.94	$ 12.21	$ 12.49
*	630	70	HPS	St Lights - Rented	389	32	$ 15.25	$ 15.60	$ 15.96
*	631	100	HPS	St Lights - Rented	553	46	$ 19.40	$ 19.85	$ 20.31
*	632	150	HPS	St Lights - Rented	799	66	$ 27.69	$ 28.33	$ 28.98
	633	250	HPS	St Lights - Rented	1283	106	$ 37.65	$ 38.52	$ 39.41
	634	400	HPS	St Lights - Rented	1886	157	$ 44.04	$ 45.05	$ 46.09
*	635	125	MV	St Lights - Rented	656	54	$ 15.10	$ 15.45	$ 15.81
*	636	175	MV	St Lights - Rented	881	73	$ 19.20	$ 19.64	$ 20.09
*	637	250	MV	St Lights - Rented	1210	101	$ 26.70	$ 27.31	$ 27.94
*	638	400	MV	St Lights - Rented	1906	158	$ 37.26	$ 38.12	$ 39.00
	639	70	Lanterns	City Lanterns - Rented	389	32	$ 56.06	$ 57.35	$ 58.67
*	640	70	HPS	St Lights - Owned	389	32	$ 5.99	$ 6.13	$ 6.27
*	641	100	HPS	St Lights - Owned	553	46	$ 7.90	$ 8.08	$ 8.27
*	642	150	HPS	St Lights - Owned	779	65	$ 10.62	$ 10.86	$ 11.11
	643	250	HPS	St Lights - Owned	1283	107	$ 16.81	$ 17.20	$ 17.60
	644	400	HPS	St Lights - Owned	1886	157	$ 26.53	$ 27.14	$ 27.76
*	645	125	MV	St Lights - Owned	656	55	$ 8.95	$ 9.16	$ 9.37
*	646	175	MV	St Lights - Owned	881	73	$ 12.13	$ 12.41	$ 12.70
*	647	250	MV	St Lights - Owned	1210	101	$ 16.75	$ 17.14	$ 17.53
	648	400	MV	St Lights - Owned	1906	159	$ 26.51	$ 27.12	$ 27.74
*	650	200	HPS	St Lights - Owned	1033	86	$ 14.63	$ 14.97	$ 15.31
	666	72	LED	St Lights - Rented	295	25	$ 13.27	$ 13.58	$ 13.89
	670	100	LED	St Lights - Rented	410	34	$ 15.44	$ 15.80	$ 16.16
	719	43	LED	St Lights - Owned	176	15	$ 2.43	$ 2.49	$ 2.55
*	720	200	HPS	Yard Lights - Rented	1033	86	$ 30.31	$ 31.01	$ 31.72
*	730	70	HPS	Yard Lights - Rented	389	32	$ 15.25	$ 15.60	$ 15.96
*	731	100	HPS	Yard Lights - Rented	553	46	$ 19.36	$ 19.81	$ 20.27
*	732	150	HPS	Yard Lights - Rented	799	66	$ 27.69	$ 28.33	$ 28.98
	733	250	HPS	Yard Lights - Rented	1283	106	$ 37.65	$ 38.52	$ 39.41
	734	400	HPS	Yard Lights - Rented	1886	157	$ 44.04	$ 45.05	$ 46.09
*	735	125	MV	Yard Lights - Rented	656	54	$ 15.10	$ 15.45	$ 15.81
*	736	175	MV	Yard Lights - Rented	881	73	$ 19.20	$ 19.64	$ 20.09
*	737	250	MV	Yard Lights - Rented	1210	100	$ 26.71	$ 27.32	$ 27.95
*	738	400	MV	Yard Lights - Rented	1906	158	$ 34.12	$ 34.90	$ 35.70
*	740	70	HPS	Yard Lights - Owned	389	32	$ 5.99	$ 6.13	$ 6.27
*	741	100	HPS	Yard Lights - Owned	553	46	$ 7.90	$ 8.08	$ 8.27
	742	150	HPS	Yard Lights - Owned	779	65	$ 10.62	$ 10.86	$ 11.11
	743	250	HPS	Yard Lights - Owned	1283	107	$ 16.81	$ 17.20	$ 17.60
	744	400	HPS	Yard Lights - Owned	1886	157	$ 26.53	$ 27.14	$ 27.76
	745	125	MV	Yard Lights - Owned	656	55	$ 8.95	$ 9.16	$ 9.37
	746	175	MV	Yard Lights - Owned	881	73	$ 12.13	$ 12.41	$ 12.70
	747	250	MV	Yard Lights - Owned	1210	101	$ 16.75	$ 17.14	$ 17.53
	748	400	MV	Yard Lights - Owned	1906	159	$ 26.51	$ 27.12	$ 27.74
	749	180	LPS	Yard Lights - Owned	869	72	$ 12.38	$ 12.66	$ 12.95
	750	200	HPS	Yard Lights - Owned	1033	86	$ 14.63	$ 14.97	$ 15.31
	751	135	LPS	Yard Lights - Owned	730	61	$ 9.85	$ 10.08	$ 10.31
	752	90	LPS	Yard Lights - Owned	521	43	$ 6.91	$ 7.07	$ 7.23
	753	250	Flood	Yard Lights - Rented	1283	107	$ 35.92	$ 36.75	$ 37.60
	754	400	Flood	Yard Lights - Rented	1886	157	$ 44.73	$ 45.76	$ 46.81
	755	250	Halide	Yard Lights - Rented	1148	95	$ 37.84	$ 38.71	$ 39.60
	756	400	Halide	Yard Lights - Rented	1878	156	$ 46.57	$ 47.64	$ 48.74
	757	1000	Halide	Yard Lights - Rented	4346	362	$ 79.93	$ 81.77	$ 83.65
	758	70	Halide	St Lights - Owned	390	32	$ 5.40	$ 5.52	$ 5.65
	759	100	Halide	St Lights - Owned	533	44	$ 7.39	$ 7.56	$ 7.73
	760	175	Halide	St Lights - Owned	894	74	$ 12.40	$ 12.69	$ 12.98
	761	250	Halide	St Lights - Owned	1148	95	$ 15.91	$ 16.28	$ 16.65
	762	400	Halide	St Lights - Owned	1878	156	$ 26.01	$ 26.61	$ 27.22
	763	1000	Halide	St Lights - Owned	4346	362	$ 60.20	$ 61.58	$ 63.00
	764	100	LED	St Lights - Owned	410	34	$ 5.68	$ 5.81	$ 5.94
	765	150	Halide	St Lights - Owned	759	63	$ 10.51	$ 10.75	$ 11.00
	766	72	LED	St Lights - Owned	295	25	$ 4.08	$ 4.17	$ 4.27
	775	107	LED	St Lights - Owned	438	37	$ 6.07	$ 6.21	$ 6.35
	780	143	LED	St Lights - Owned	586	49	$ 8.12	$ 8.31	$ 8.50
	785	175	LED	St Lights - Owned	718	60	$ 9.93	$ 10.16	$ 10.39

* These charges are applicable to existing fixtures only.

Maritime Electric Company, Limited
Schedule of Rates

		March 1, 2016	March 1, 2017	March 1, 2018
610	Pole Rental -Wood	$ 4.38	$ 4.38	$ 4.38
611	Pole Rental -Concrete	$ 7.96	$ 7.96	$ 7.96
	Unmetered Rates (based on 100 watt fixture)			
810	8 Hour Lighting per kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
820	12 Hour Lighting per kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
830	24 Hour Lighting per kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category		
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week			
234	Customer Owned Outdoor Recreational Lighting			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 5,000 kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Energy Charge per kWh for balance of kWh	$ 0.1020	$ 0.1043	$ 0.1067
	Short Term Unmetered Rates	Currently no customers in this rate category		
	Energy Charge:			
	per kWh of estimated consumption	$ 0.1661	$ 0.1699	$ 0.1738

Connection Charge:	Three-Phase
A. Connecting to existing secondary voltage	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Three-Phase
(1) Up to and including 10 kVA	$209.17
(2) 11 kVA to 15 kVA	$301.01
(3) 16 kVA to 25 kVA	$336.64
(4) 26 kVA to 37 kVA	$336.64
(5) 38 kVA to 50 kVA	$336.64
(6) 51 kVA to 75 kVA	$523.96
(7) 76 kVA to 125 kVA	$555.59
(8) Above 125 kVA	$594.94

Maritime Electric Company, Limited
Schedule of Inputs

	2016	2017	2018
Summary of Forecast NPP and Sales			
Net Purchased & Produced (kWh)	1,287,845,600	1,314,420,900	1,340,478,000
Sales (kWh)			
Residential	563,660,000	580,352,000	596,667,000
General Service	391,720,000	394,887,000	397,870,000
Large Industrial	131,336,000	131,704,000	132,086,000
Small Industrial	98,933,000	103,731,000	108,397,000
Street Lighting	5,670,000	5,390,000	5,109,000
Unmetered	2,460,000	2,478,000	2,491,000
	1,193,779,000	1,218,542,000	1,242,620,000
ECAM Base Rate per kWh (Effective March 1)	0.08605	0.08988	0.09161
RORA Rebate per kWh (Effective March 1)	0.00410	0.00473	0.00345
Capital Structure (Average)			
Debt	59.10%	60.00%	60.00%
Equity	40.90%	40.00%	40.00%
	100.00%	100.00%	100.00%
Return on Average Common Equity	9.35%	9.35%	9.35%
Rate Base (Average)	340,818,000	359,398,000	374,717,000
Return on Average Rate Base	7.43%	7.17%	7.05%
Average Short Term Financing Rate	2.9%	3.3%	3.5%
Annual Capital Expenditures	30,660,000	29,399,000	30,815,000
Summary of Revenues and Expenses			
Basic Rate Revenue			
Residential	92,947,000	97,759,000	102,449,000
General Service	60,012,000	62,138,000	64,033,000
Large Industrial	10,854,000	11,208,000	11,448,000
Small Industrial	12,603,000	13,494,000	14,331,000
Street Lighting	2,137,000	2,101,000	2,022,000
Unmetered	397,000	414,000	422,000
	178,950,000	187,114,000	194,705,000
Transmission Revenue	8,110,000	12,380,000	13,963,000
Miscellaneous Revenue	1,627,000	2,025,000	1,953,000
Total Revenue	188,687,000	201,519,000	210,621,000
Operating Expenses			
Energy Costs	111,986,000	117,726,000	122,657,000
Distribution	8,176,000	8,727,000	8,968,000
Transmission - OATT (Cable)	-	4,133,000	5,590,000
Transmission - OATT (Other)	6,665,000	6,813,000	6,937,000
Corporate	10,094,000	10,484,000	10,783,000
Amortization - Fixed Assets & Other	21,139,000	22,397,000	23,650,000
Financing Expenses	12,388,000	12,433,000	12,645,000
Income Taxes	5,768,000	5,943,000	6,123,000
Net Earnings	12,471,000	12,863,000	13,268,000

Appendix 3
Energy Cost Adjustment Mechanism Formula

The Energy Cost Adjustment Mechanism ("ECAM") applies to approved basic rates for meter readings taken on or after March 1, 2016 as follows:

Base Cost of Purchased and Produced Electricity

The rate adjustment of ECAM will apply when the cost of purchased and produced electricity increases or decreases from the Base Cost. The forecast Base Rate Cost for purchased and produced electricity is $0.08605/KWh and may be adjusted as ordered by the Commission.

Deferral of Increases or Decreases from the Base Cost

The deferral of increases or decreases in purchased and produced electricity from the Base Cost shall be calculated at the end of each month as follows:

1. Determine the total cost of purchasing and producing electricity in the month including any amounts amortized to ECAM as Ordered by the Commission;
2. Determine the net kilowatt hours of purchased and produced energy in the month;
3. Multiply the quantity of net purchased and produced energy determined in (2) above by the forecast Base Rate Cost of $0.08605/KWh to determine the base cost of electricity;
4. Subtract the base cost of electricity determined in (3) above from the total cost of purchasing and producing electricity determined in (1) above to calculate the excess or deficiency of the cost of purchased or produced electricity from the base cost;
5. Add the excess (or deficiency) of the cost of purchased or produced energy calculated in (4) above to the corresponding excess (or deficiency) costs on the Balance Sheet.

Appendix 3
Energy Cost Adjustment Mechanism Formula

Calculation of ECAM Rate Adjustment Applied to Customers' Bills

The ECAM Rate Adjustment applied to Customers' bills shall be calculated as follows and applied to Customers' bills for not less than twelve months unless otherwise Ordered by the Commission.

6. Determine the total of the excess (or deficiency) costs on the Balance Sheet at the end of the third month proceeding the month in which the ECAM rate will be applied.

7. Determine the forecast total kilowatt hour sales for the twelve month period commencing with the month in which the ECAM rate will be applied.

8. Divide the amount calculated in (6) above by the amount calculated in (7) above to determine the ECAM rate adjustment required in cents per kilowatt hour sold and which will be applied to Customers' bills. Rate adjustment shall be calculated to the nearest three decimal places (five decimal places on the dollar).

Appendix 4
Weather Normalization Mechanism and Reserve

Purpose

The purpose of a Weather Normalization Reserve is to stabilize electricity rates to customers by removing the volatility in sales and energy supply costs caused by temperature changes relative to historical averages. Where the Heating Degree Days[1] (HDD) variation is above normal, the Company will experience incremental marginal net revenue (revenue less energy costs) which would need to be returned to customers but when HDD variation is below normal there will be a shortfall in net revenue which will need to be recovered from customers.

Calculation of Contribution to the Reserve

The balance in the Weather Normalization Reserve on the Company's balance sheet represents the cumulative monthly change in contribution from sales resulting from variations in HDD from normal and should, over time, net to zero.

As illustrated in Schedule 1, in a year when HDD are higher than normal (2013 and 2014), a marginal net revenue amount will be subtracted on the Company's income statement and added to the Reserve. When HDD are lower than normal (2010 – 2012), a marginal net revenue amount will be added to the Company's income statement and subtracted from the Reserve. Over the ten year period, the variation from average HDD balances to zero as does the balance in the reserve account.

As a formula,

$$\text{Contribution to Weather Normalization Reserve} = \begin{array}{c}\text{MWh Variation}\\ \text{from Average}\end{array} \times \begin{array}{c}\text{Marginal Net}\\ \text{Revenue}\end{array}$$

[1] http://climate.weather.gc.ca/glossary_e.html - Heating degree-days for a given day are the number of degrees Celsius that the mean temperature is below 18°C. If the temperature is equal to or greater than 18°C, then the number will be zero. For example, a day with a mean temperature of 15.5°C has 2.5 heating degree-days; a day with a mean temperature of 20.5°C has zero heating degree-days.

Where,

MWh Variation from Average = (Actual HDD Value - Average HDD Value) X (MWh per HDD Coefficient)

Marginal Net Revenue = Forecast Unit Revenue per MWh - Forecast Unit Energy Cost per MWh

The following describes the components and operation of the Weather Normalization Reserve.

<u>Determination of Average HDD Value</u>

The first step in establishing the mechanics of the Weather Normalization Reserve is the determination of the Average HDD Value using the rolling 10 year average HDD value based upon the most recent 10 years of information available as measured by Environment Canada for the Charlottetown Airport weather station. As calculated in Schedule 2, the average annual HDD value to be used for 2016 is calculated to be 4,339 (2005-2014).

<u>Calculation of MWh/HDD Coefficient</u>

The next step is the determination of the annual MWh/HDD Coefficient (the "Coefficient") to be used for the upcoming year using econometric modelling. As shown in Schedule 3, using a linear regression analysis the Coefficient for 2016 is calculated at 41.73 (based on October 2014 to May 2015 data), which is the estimated change in MWh sales (customer usage) resulting from a unit variation in HDD (i.e. 41.73 MWh per HDD). The calculation excludes from the analysis the data for the months of June to September as these months are primarily cooling months, which would distort the Coefficient calculation for HDD and reduce its accuracy. In addition, only sales for year round Residential, General Service and Small Industrial classes are used as these are the only classes materially affected by variations in HDD.

Calculation of Marginal Net Revenue

The final variable is the Marginal Net Revenue rate which is calculated as the forecast unit revenue per MWh less the forecast unit energy cost per MWh. For the same reason noted above, the unit revenue is comprised of only demand and energy charge revenues (i.e. excluding the service charge or site revenue) for Residential, General Service and Small Industrial classes as these are the only revenue factors and rate classes affected by variations in HDD. In addition, the energy cost per MWh for the year is set at the Base Rate in the ECAM for the particular year as approved by the Commission. Schedule 4 shows the calculation of the 2016 Marginal Net Revenue Rate of $50.42/MWh.

Application

The determination of the Weather Normalization Reserve adjustment on the Company's balance sheet is to be calculated on a monthly basis as described above, effective January 1, 2016.

Revisions to the components of MWh Variation from Average and Marginal Net Revenue formulas for a calendar year are to be submitted to the Commission for approval on or before October 31 of the year prior thereto.

SCHEDULE 1
Illustration of Annual Change in Weather Normalization Reserve

	Heating Degree Days (below 18 deg C)		Space heating load			Weather Normalization Reserve	
Year	Actual HDD	Variation from Average (4,339 days)	Coefficient (MWh/HDD)	Variation from Average (MWh)	Marginal Net Revenue ($/MWh)	Increase (Decrease) ($)	Balance Owing (Recoverable) ($)
2005	4,448	109	41.73	4,553	50.42	229,577	229,577
2006	3,996	(343)	41.73	(14,310)	50.42	(721,558)	(491,981)
2007	4,677	338	41.73	14,110	50.42	711,458	219,477
2008	4,389	50	41.73	2,091	50.42	105,425	324,901
2009	4,559	220	41.73	9,186	50.42	463,153	788,054
2010	3,968	(371)	41.73	(15,479)	50.42	(780,478)	7,575
2011	4,231	(108)	41.73	(4,503)	50.42	(227,052)	(219,477)
2012	4,055	(284)	41.73	(11,848)	50.42	(597,406)	(816,882)
2013	4,519	180	41.73	7,516	50.42	378,981	(437,901)
2014	4,547	208	41.73	8,685	50.42	437,901	(0)
		(0)		(0)			

SCHEDULE 2
Calculation of 10-Year Average HDD

Month	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	10 year average (2005 - 2014)
Jan	854	626	737	728	866	686	744	715	812	771	754
Feb	698	677	763	686	664	608	697	700	672	717	688
Mar	654	594	643	694	675	556	621	572	603	760	637
Apr	406	411	491	418	420	367	420	379	441	453	421
May	314	204	308	286	245	262	259	224	235	308	265
Jun	117	55	121	95	102	114	150	119	107	120	110
Jul	29	5	29	0	42	13	21	12	13	1	17
Aug	17	52	38	20	30	21	14	5	17	28	24
Sep	82	116	120	121	135	107	90	76	106	118	107
Oct	247	290	248	300	345	290	249	240	291	228	273
Nov	402	374	446	421	392	429	397	424	472	461	422
Dec	628	592	733	620	643	515	569	589	750	582	622
	4,448	3,996	4,677	4,389	4,559	3,968	4,231	4,055	4,519	4,547	**4,339**
										Standard Deviation	258

SCHEDULE 3
Calculation of MWh/HDD Coefficient

Year	Month	Days in month	Actual HDD	HDD per day	Reported sales (MWh)	Fewer hours of daylight	Average HDD per day	Average MWh per day
2014	Jul	31	1	0.0	70,921			
	Aug	31	28	0.9	79,973			
	Sep	30	118	3.9	74,136			
	Oct	31	228	7.4	72,767	2.52	5.6	2,426
	Nov	30	461	15.4	84,725	4.07	11.4	2,733
	Dec	31	582	18.8	88,471	5.21	17.1	2,949
2015	Jan	31	829	26.7	103,575	5.40	22.8	3,341
	Feb	28	858	30.6	107,097	4.53	28.7	3,455
	Mar	31	743	24.0	95,132	3.11	27.3	3,398
	Apr	30	537	17.9	90,109	1.53	20.9	2,907
	May	31	233	7.5	78,424	0.00	12.7	2,614
	Jun	30		-	72,384			

Linear regression results:
(Oct 2014 - May 2015)

HDD	Daylight hrs	b	
41.73	50.89	2045.89	coefficients
3.43	14.71	69.33	standard error coefficients
0.98	68.90	#N/A	R^2, standard error y
106.89	5.00	#N/A	F, degrees of freedom
1014942	23737.67	#N/A	Regression SS, residual SS
12.17	3.46	29.51	t values

SCHEDULE 4
Calculation of Forecast Marginal Net Revenue Rate for 2016

Rate Class	2016 (Forecast) Revenue ($)	Sales (MWh)	Unit Revenue ($/MWh)	
Residential	70,955,849	545,578		*
General Service I	55,143,280	372,955		*
General Service II	1,530,913	10,751		
Small Industrial	12,692,471	98,933		
Total	140,322,513	1,028,217	$ 136.47	
ECAM Base Rate (Proposed)			$ (86.05)	
Marginal Net Revenue Rate			$ 50.42	

* Excludes revenue and kWh sales from seasonal customers

Appendix 5
Summary of Adjustments to Depreciation Rates
Related to Electrical Plant Effective January 1, 2016

Depreciable Group	Original Cost At 12/31/2014[1]	Existing Annual Accrual Rate	Existing Annual Accrual Amount	Proposed Annual Accrual Rate[1]	Proposed Annual Accrual Amount[1]
	A	B	C=AxB	D=E/A	E
DEPRECIABLE ELECTRICAL PLANT					
Total Steam Production Plant	61,170,863	2.50	1,529,272	4.53	2,768,484
Bordon Generating Station	12,768,390	2.50	319,210	4.81	614,008
Combustion Turbine #3	34,716,216	2.50	867,905	2.28	791,853
Total Transmission Plant	96,209,123	2.30	2,212,810	2.27	2,182,162
Distribution Plant					
Poles, Towers and Fixtures	58,696,260		1,760,888		2,051,434
Line Transformers	61,376,167		1,841,285		2,018,632
Meters	13,399,311		401,979		671,613
Other Net	171,860,410		5,162,216		5,402,998
Total Distribution Plant	305,332,148	3.00	9,166,368	3.32	10,144,677
General Plant					
Office Furniture & Equip – Computer Hardware	1,388,244		191,578		277,649
Office Furniture & Equip – Computer Software	4,978,910		687,090		497,891
Transportation Equipment	9,695,001		727,125		678,974
Other Net	22,457,753		985,590		842,004
Total General Plant	38,519,908	6.73	2,591,382	5.96	2,296,518
Total Fully Amortized General Plant	1,988,102	6.51	129,426	0.00	-
TOTAL ANNUAL IMPACT	**$550,704,751**	**3.05**	**$16,816,372**	**3.41**	**$18,797,702**

References:
1. 2014 Study - Page VI – Table 1 (Data as at December 31, 2014)

Appendix 6
Summary of Amortization of Accumulated Reserve Variance and Increase in Depreciation Expense
Related to Charlottetown Thermal Generating Station (CTGS) Effective January 1, 2016

DEPRECIABLE GROUP	Original Cost At 12/31/2014	Annual Accrual Amount	Reserve Variance Amortization	Total Annual Depreciation	Annual Rate % Including True-Up
	A	B	C	D=B+C	E=D/A
CTGS					
Structures & Improvements	8,945,331	478,270	358,012	836,282	9.35%
Boiler Plant Equipment	26,337,761	1,192,921	822,136	2,015,057	7.65%
Turbogenerator Units	22,091,772	970,221	841,223	1,811,444	8.20%
Accessory Electrical Equipment	2,283,113	63,728	53,650	117,378	5.14%
Miscellaneous Power Plant Equipment	1,512,887	63,344	42,447	105,791	6.99%
TOTAL – CTGS	**$61,170,863**	**$2,768,484**	**$2,117,468**	**$4,885,952**	**7.99%**

Reference:
2014 Study - Part VI – Table 3 (Data as at December 31, 2014)

APPENDIX A

2016 General Rate Agreement

RECEIVED
JAN 29 2016
The Island Regulatory and Appeals Commission

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER OF: Section 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental to such an order.

- and -

IN THE MATTER OF: Section 26 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and Section 12 of the Island Regulatory and Appeals Commission Act (R.S.P.E.I. 1988, Cap. I-11) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission with respect to input factors for the period between January 1, 2016 and February 29, 2016 and to establish rates of depreciation with respect to the Company's several classes of property for the period beginning January 1, 2016 and for certain approvals incidental to such an order.

MINUTES OF SETTLEMENT

WHEREAS on October 28, 2015, the Applicant, Maritime Electric Company Limited ("MECL") filed a General Rate Application ("GRA");

AND WHEREAS on July 23, 2015 MECL filed a Depreciation Application;

AND WHEREAS on June 3, 2015 MECL filed a Demand Side Management (DSM) Application and on November 3, 2015 the Commission issued Order UE 15-02;

AND WHEREAS on December 13, 2006 MECL filed an Open Access Transmission Tariff ("OATT") Application and on March 4, 2008 the Commission issued order UE 08-03;

AND WHEREAS the GRA, Depreciation Application, DSM Application and OATT Application are collectively referred to herein as "the Applications";

AND WHEREAS the Government of Prince Edward Island, as represented by the Minister of Transportation, Infrastructure and Energy ("the Government") intervened in the Applications;

AND WHEREAS notice of the Applications was published in the local newspaper, and questions and comments were received from members of the general public, the Commission and the Government;

AND WHEREAS MECL and the Government have reached agreement on the matters in issue in the GRA and Depreciation Applications, and have made certain assumptions about DSM expenses and OATT revenue, all of which are contained in the 2016 General Rate Agreement ("the Agreement") attached as Appendix A;

AND WHEREAS MECL and the Government agree that to the extent that the terms of the Agreement differ from the relief sought by MECL in the GRA and Depreciation Applications, the terms of the Agreement shall prevail and shall be dispositive of MECL's GRA and Depreciation Applications;

AND WHEREAS the Agreement is subject to review and approval by the Commission.

THE UNDERSIGNED respectfully request the Commission to approve the Agreement attached hereto as Appendix A, and set new electricity rates effective March 1, 2016 on the basis of this Agreement.

AGREED, and signed by legal counsel THIS 29TH DAY OF JANUARY, 2016.

MARITIME ELECTRIC COMPANY, LIMITED

Per: D. Spencer Campbell, Q.C.

GOVERNMENT OF PRINCE EDWARD ISLAND, as represented by the Minister of Transportation, Infrastructure and Energy

Per: J. Gordon MacKay, Q.C.

APPENDIX A

2016 GENERAL RATE AGREEMENT

THIS AGREEMENT made this 28th day of January 2016

BETWEEN:

THE GOVERNMENT OF PRINCE EDWARD ISLAND as represented by the Minister of Transportation, Infrastructure and Energy (hereinafter referred to as "Province")

OF THE FIRST PART

AND:

MARITIME ELECTRIC COMPANY, LIMITED a body corporate, duly incorporated under the laws of Canada, as represented by its President and Chief Executive Officer (hereinafter referred to as "MECL")

OF THE SECOND PART

WHEREAS in recognition of the fact that a collaborative approach by the parties in securing least cost, reliable sources of electric energy and related capacity at stable rates is in the best interests of Prince Edward Island ("Island") consumers of electricity the parties hereto entered into an Agreement known and styled as the Prince Edward Island Energy Accord ("Accord");

AND WHEREAS the term of the Accord is from November 12, 2010, to February 29, 2016;

AND WHEREAS the parties recognize that the primary goal of reducing the cost of electricity to Island consumers and ensuring price stability and rate predictability can best be achieved by continuing the collaborative approach between the parties and adding certainty to rates, tolls and charges for electric energy in the Province;

AND WHEREAS the Province is in the process of developing a new provincial energy strategy to assist with short and long term policies, programs and approaches to energy and sustainability;

AND WHEREAS the parties agree to continue to work collaboratively to implement innovative and effective demand side management ("DSM") policies to improve energy efficiency and reduce energy consumption in the Province, leading to a substantive reduction in carbon emissions and reliance on fossil fuels;

NOW THEREFORE THIS AGREEMENT WITNESSETH THAT in consideration of the premises, the mutual covenants and agreements herein and subject to the terms and conditions in this Agreement, the aforesaid parties to this Agreement agree as follows:

Article 1 - 2016 General Rate Agreement

1.1 This Agreement shall be known and styled as the 2016 General Rate Agreement ("Agreement").

1.2 The purpose of the Agreement is:

(i) To ensure continued reliable sources of electric energy and related capacity at stable, reasonable rates for Island consumers; and

(ii) To provide price stability and rate predictability for Island electricity consumers over the next three (3) years beginning on March 1, 2016.

1.3 The Term of the Agreement is for the period commencing on March 1, 2016 and ending on February 28, 2019.

Article 2 - General Rate Application

2.1 MECL currently has before the Island Regulatory and Appeals Commission ("Commission") a General Rate Application ("GRA"), filed on October 28, 2015.

2.2 The parties agree that MECL shall be entitled to the relief sought in the General Rate Application subject to the exceptions set out in section 2.3.

2.3 The parties agree that:

(i) A return on rate base resulting in a 9.35% return on average common equity shall be approved for MECL for each year of the Agreement;

(ii) MECL shall apply the rates, tolls and charges as set out in Appendix 1 attached hereto for the period March 1, 2016 to February 28, 2019, which rates, tolls and charges are based upon the forecasted values and input factors set out in Appendix 2 and such other forecasted values and input factors as may be agreed to by the parties. For greater certainty, MECL shall be entitled to collect the revenue requirement set out in Appendix 2 in order to apply the schedule of rates, tolls and charges set out in Appendix 1; and

(iii) Consideration of changes to the multi-block residential energy pricing structure, and the related changes in other Company rate structures, shall be deferred until following the termination of the Agreement.

2.4 As a result of the Agreement, the cost of electricity for a typical MECL customer for the duration of the Agreement will be limited to a maximum increase of 2.3% per year.

Article 3 - Return on Equity Calculations

3.1 On December 2, 2015, *An Act to Amend the Electric Power Act*, S.P.E.I. 2015, c. 25, received Royal Assent in the Legislative Assembly ("Amending Act").

3.2 The *Amending Act*, among other things, includes the repeal of the current section 12.1 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4 ("Electric Power Act"), and substitution of the following, to be effective January 1, 2017:

> *12.1 Maritime Electric Company, Limited shall, as determined in accordance with generally accepted accounting principles,*

> *(a) maintain at all times not less than 35 per cent of its capital invested in the power system in the form of common equity; and*
>
> *(b) ensure that, for the year, not more than 40 per cent of its capital is invested in the power system in the form of common equity.*

3.3 The parties agree that:

(i) the proper determination of MECL's capital invested in the power system for the purposes of applying the provisions of the *Amending Act* and in accordance with this Agreement is based upon MECL's average capital invested in the power system for the year ("Average Annual Capital Investment"); and

(ii) MECL's Average Annual Capital Investment shall be calculated by using MECL's equity levels at the beginning and end of a given year.

3.4 The parties further agree that:

(i) the provision of the *Amending Act* establishing MECL's maximum Average Annual Capital Investment for a given year is for the purpose of calculating MECL's maximum allowable earnings; and

(ii) for the purpose of calculating MECL's earnings as an input factor in the years 2017 and 2018, MECL's maximum allowable earnings shall be based upon the Return on Average Equity set out in subsection 2.3(i) of this Agreement and a forecast Average Annual Capital Investment of Forty Percent (40%).

Article 4 - Rate of Return Adjustment ("RORA")

4.1 Where, during the term of the Agreement, the cumulative amount refunded to customers on a per kWh basis through the RORA account, as set out in Appendix 2, exceeds or is less than the balance in the RORA account on the Company's audited balance sheet at December 31, 2015, the Company shall recover or refund such net amount from or to customers over a reasonable period commencing March 1, 2019 as directed by the Commission.

4.2 In the event that MECL's return on average common equity exceeds the return on average common equity, as set out in Appendix 2, MECL shall return to its customers that portion of its earnings which exceed the return on average common equity set out in Appendix 2 commencing March 1, 2019 as directed by the Commission.

Article 5 - Depreciation Application

5.1 MECL currently has before the Commission an application for the establishment of rates of depreciation with respect to MECL's several classes of property, filed on July 23, 2015 ("Depreciation Application").

5.2 The parties agree that

(i) MECL shall adopt depreciation rates calculated as of January 1, 2016, as proposed in the Depreciation Application, which rates shall remain in effect until the later of February 28, 2019 or varied by the Commission;

(ii) MECL shall be entitled to record and incorporate into depreciation rates the recommended amortization of the accumulated reserve variance associated with the Charlottetown Thermal Generating Station commencing in 2016 and as outlined in Appendix 4 of the Depreciation Application;

(iii) MECL shall file a Decommissioning Study with respect to the Charlottetown Thermal Generating Station with the Commission no later than June 30, 2018; and

(iv) MECL shall file an updated Depreciation Study with the Commission no later than June 30, 2018, based on financial results to December 31, 2017. The filing will include any proposed changes in depreciation rates to ensure that the accumulated reserve variance for all classes of property are addressed prudently, and over a reasonable period of time, and that the results of the Decommissioning Study are incorporated into a prudent plan to ensure an adequate future site removal provision is provided for at the Charlottetown Thermal Generating Station.

Article 6 - Demand Side Management and Open Access Transmission Tariff Applications

6.1 On June 3, 2015, MECL filed an application with the Commission for approval of a proposed DSM plan ("DSM Application").

6.2 On November 3, 2015, the Commission issued Order UE15-02 with respect to the DSM Application. In Order UE15-02, the Commission:

(i) Approved the public outreach and education component of the proposed DSM plan, with an annual cost of $167,500 to be recovered through customer rates as a component of the Energy Cost Adjustment Mechanism;

(ii) Did not approve any of the other components of the proposed DSM plan; and

(iii) Indicated it would issue an order in due course requiring MECL to file a new Energy Efficiency and DSM plan, pursuant to Section 16.1 of the *Electric Power Act*.

6.3 December 13, 2006, MECL filed an application with the Commission for approval of a proposed Open Access Transmission Tariff ("OATT Application").

6.4 On March 4, 2008, the Commission issued Order UE08-03 with respect to the OATT Application. In Order UE08-03, the Commission ordered, among other things, that:

(i) The October 3, 2007 OATT filed by MECL was approved effective June 30, 2008 as an interim tariff rate for the transmission of electricity by MECL and the collection of which rates were, until a final rate was set, subject to such commercial collection agreements as MECL and its OATT customers may from time to time agree upon; and

(ii) The Commission may adjust the interim tariff or deal with the collection thereof pending consideration of evidence filed by the City of Summerside and MECL and any hearing which may result.

6.5 The parties agree that the DSM Application and the OATT Application are both subject to further regulatory oversight and that Appendix 2 assumes certain DSM expenditures and OATT revenue. To the extent that the assumed expenditures and revenue differ from the actual amounts, if any, ordered by the Commission, MECL shall recover or refund such net amounts from or to customers over a reasonable period as directed by the Commission.

Article 7 - Interconnection Upgrade Project

7.1 The parties have entered into a Memorandum of Understanding ("MOU") and a Construction Agency Agreement (CAA) with respect to the Interconnection Upgrade Project ("Project").

7.2 MECL is now actively engaged as the Construction Agent for the PEI Energy Corporation and is working towards having the interconnection upgrade operating in late 2016.

7.3 The parties agree that the Project shall continue to proceed in accordance with the MOU, CAA and related documents, and that Project costs and their recovery from MECL customers, shall be based upon the forecasted values and input factors set out in Appendix 2. For greater certainty, recovery of MECL's portion of Project costs in accordance with Appendix 2 shall be a component of the Energy Cost Adjustment Mechanism and shall survive the expiration of this Agreement.

Article 8 - Implementation

8.1 The parties agree to jointly seek Commission approval for the implementation of the provisions of this Agreement as being an agreed upon resolution to the matters in issue with respect to the General Rate Application and the Depreciation Application.

8.2 For greater certainty, none of the provisions contained in this Agreement shall be enforceable unless and until all of the provisions of the Agreement are either approved by the Commission or legislatively authorized by amendments to the *Electric Power Act*, or a combination thereof.

Article 9 - Communication

9.1 Official public announcements with regard to matters addressed by this Agreement will be held from time to time, as agreed by the parties. The parties agree that Province shall be primarily responsible for public announcements with respect to this Agreement and each party will use their best efforts to provide the other with advance notice of any public announcement. The parties will co-operate in organizing media conferences, announcements and official ceremonies.

9.2 This Agreement and any information provided pursuant to this Agreement may be subject to release under the *Freedom of Information and Protection of Privacy Act* R.S.P.E.I. 1988, Cap F-15.01 (the "Act"). MECL will be consulted prior to the release of any information. The Parties recognize for purposes of the *Act* that the information which will be provided by MECL may be confidential and disclosure of this information could reveal trade secrets and commercial, financial, labour relations, scientific or technical information of MECL and that disclosure of this information or any part of it could significantly harm the competitive position of MECL and result in undue loss to MECL and its customers.

Article 10 - Dispute Resolution

10.1 Unless otherwise expressly provided for herein, any claim or controversy between the parties arising out of or relating to the execution, interpretation and performance of the Agreement (including the validity, scope and enforceability of this provision) shall be identified in writing and presented to the other party. Within twenty (20) days after delivery of such notice of dispute a representative from each of the parties shall meet at a mutually acceptable time and place, and thereafter as often as they reasonably deem necessary, to attempt to resolve the dispute in good faith. All reasonable requests for information made by one party to another shall be honoured. All negotiations pursuant to this clause are confidential and shall be treated as compromise and settlement negotiations for purposes of applicable rules of evidence.

10.2 If the parties are unable to resolve a dispute within thirty (30) days, then any unresolved claim or controversy between the parties arising out of or relating to the execution, interpretation and performance of this Agreement shall be settled by arbitration before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters. The arbitrator(s) shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the *Arbitration Act*, RSPEI 1988, Cap. A-16..

10.3 Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the parties in writing of such decision and the reasons therefore. The decision of the arbitrator(s) shall be final and binding upon the parties.

10.4 Each party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) one half the cost of the single arbitrator jointly chosen by the Parties.

In the event that it is necessary to enforce such award, all costs of enforcement shall be payable and paid by the party against whom such award is enforced.

Article 11 - General Provisions

11.1 The Parties agree that this Agreement shall be governed by and construed and interpreted in accordance with the laws of the Province of Prince Edward Island and the laws of Canada applicable therein. All disputes, controversies or differences whatsoever arising under, in connection with or incident to the Agreement shall be exclusively governed by and construed and interpreted in accordance with the laws of Prince Edward Island and the laws of Canada applicable therein.

11.2 The parties' rights and obligations hereunder will bind and inure to the benefit of their respective successors and permitted assigns. Neither party shall assign or delegate its obligations under this Agreement either in whole or in part without the prior written consent of the other party.

11.3 Any notice, demand or other communication required or permitted by this Agreement to be given hereunder shall be in writing and shall be delivered by courier during normal business hours and left with a responsible employee at the relevant address set forth below or sent by facsimile transmission or other means of electronic communication that produces a written record and confirms receipt:

(i) To: Maritime Electric Company, Limited
180 Kent Street
P0 Box 1328
Charlottetown, PE C1A 7N2

Attention: Vice President, Corporate Planning and Energy Supply

(ii) To: Province of Prince Edward Island
4th Floor, Jones Building
11 Kent Street
PO Box 2000
Charlottetown, PE C1A 7N8

Attention: CEO, Prince Edward Island Energy Corporation

11.4 Any notice, demand or other communication so given or made shall be deemed to have been given and received on the day of delivery, if so delivered, and on the day of sending, by electronic transmission, if delivered or sent during the normal business hours of the addressee on a business day and, if not, on the first business day thereafter. Any party may from time to time change its address for notice by notice to the other parties hereto given in the manner aforesaid.

11.5 Nothing in this Agreement nor any act of the parties hereto shall be construed, implied or deemed to create an agency, partnership, joint venture or employer and employee relationship between them. Neither this Agreement nor any of its provisions shall be construed as a commitment by any of the parties to engage any other party in any work, nor as any commitment to proceed, directly or indirectly, with any business relationship between the parties. Any such commitment shall be contained only in any definitive agreements the parties may enter into in connection with any such relationship. This Agreement does not oblige either party to disclose any information to the other party.

11.6 Preparation of this Agreement has been a joint effort of the Parties and resulting documents shall not be construed more severely against one of the Parties than the other. Any rule of construction that ambiguities are to be resolved against the drafting party shall not be employed in the interpretation of this Agreement or any amendments or its appendices hereto.

11.7 The Parties agree that each of them shall, upon reasonable request to the other, do or cause to be done all further lawful acts, deeds and assurances whatever, for the better performance of the terms and conditions of this Agreement.

11.8 This Agreement may be executed in counterparts, each of which so executed shall be deemed to be an original, and together which shall be deemed to be but one and the same instrument. Delivery or acceptance of this Agreement or any portion thereof by facsimile transmission or digitally, or in any electronic fashion, shall have the same effect as if delivered personally and any such transmission signature, initial or notation, shall have the same effect as if it were an original and shall be binding upon the maker thereof.

11.9 The parties agree that upon application by either party the Commission may, by order, amend the rates, tolls and charges as set out herein if the Commission is satisfied that a material change in circumstances has occurred since the date of this Agreement.

IN WITNESS WHEREOF this Agreement has been duly executed by the parties hereto, each of whom represents that the signatory has the power to bind the party hereto.

Witness	**MARITIME ELECTRIC COMPANY, LIMITED** Per: Fred O'Brien Name: Fred J. O'Brien Title: President and Chief Executive Officer
Kim Howatt Witness	**GOVERNMENT OF PRINCE EDWARD ISLAND** As represented by the Minister of Transportation, Infrastructure and Energy Paula Biggar Name: Honourable Paula J. Biggar

Maritime Electric Company, Limited
Schedule of Rates

Rate Code		March 1, 2016	March 1, 2017	March 1, 2018
110	**Residential Urban**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance kWh	$ 0.1079	$ 0.1108	$ 0.1142
130	**Residential Rural**			
	Service Charge	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance kWh	$ 0.1079	$ 0.1108	$ 0.1142
131	**Residential Seasonal**			
	Service Charge	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance of kWh	$ 0.1079	$ 0.1108	$ 0.1142
133	**Residential Seasonal Option**			
	Service Charge	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1356	$ 0.1396	$ 0.1437
	Energy Charge per kWh for balance of kWh	$ 0.1079	$ 0.1108	$ 0.1142
232	**General Service I**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1664	$ 0.1717	$ 0.1767
	Energy Charge per kWh for balance of kWh	$ 0.1090	$ 0.1119	$ 0.1154
233	**General Service I - Seasonal Operators Option**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1664	$ 0.1717	$ 0.1767
	Energy Charge per kWh for balance of kWh	$ 0.1090	$ 0.1119	$ 0.1154
320	**Small Industrial**			
	Demand Charge - per kW	$ 7.46	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1630	$ 0.1682	$ 0.1731
	Energy Charge per kWh for balance of kWh	$ 0.0826	$ 0.0844	$ 0.0872
310	**Large Industrial**			
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0675	$ 0.0694	$ 0.0714
340	**Long Term Contract** (Currently no customers in this rate category)			
	Demand Charge per kW	$ 15.51	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.0911	$ 0.0933	$ 0.0963
330	**Short Term Contract** (Currently no customers in this rate category)			
	Demand Charge - per kW	$ 16.79	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.0929	$ 0.0951	$ 0.0981
	Energy Charge per kWh for balance of kWh in the month	$ 0.0773	$ 0.0789	$ 0.0814

Appendix 1

Maritime Electric Company, Limited
Schedule of Rates

	Rate Code	Lamp Wattage	Type		Annual kWh	Monthly kWh	March 1, 2016	March 1, 2017	March 1, 2018
	619	43	LED	St Lights - Rented	176	15	$ 11.53	$ 11.80	$ 12.07
*	620	200	HPS	St Lights - Rented	1033	86	$ 33.15	$ 33.91	$ 34.69
	625	50	LED	St Lights - Rented	205	17	$ 11.94	$ 12.21	$ 12.49
*	630	70	HPS	St Lights - Rented	389	32	$ 15.25	$ 15.60	$ 15.96
*	631	100	HPS	St Lights - Rented	553	46	$ 19.40	$ 19.85	$ 20.31
*	632	150	HPS	St Lights - Rented	799	66	$ 27.69	$ 28.33	$ 28.98
	633	250	HPS	St Lights - Rented	1283	106	$ 37.65	$ 38.52	$ 39.41
	634	400	HPS	St Lights - Rented	1886	157	$ 44.04	$ 45.05	$ 46.09
*	635	125	MV	St Lights - Rented	656	54	$ 15.10	$ 15.45	$ 15.81
*	636	175	MV	St Lights - Rented	881	73	$ 19.20	$ 19.64	$ 20.09
*	637	250	MV	St Lights - Rented	1210	101	$ 26.70	$ 27.31	$ 27.94
*	638	400	MV	St Lights - Rented	1906	158	$ 37.26	$ 38.12	$ 39.00
	639	70	Lanterns	City Lanterns - Rented	389	32	$ 56.06	$ 57.35	$ 58.67
*	640	70	HPS	St Lights - Owned	389	32	$ 5.99	$ 6.13	$ 6.27
*	641	100	HPS	St Lights - Owned	553	46	$ 7.90	$ 8.08	$ 8.27
*	642	150	HPS	St Lights - Owned	779	65	$ 10.62	$ 10.86	$ 11.11
	643	250	HPS	St Lights - Owned	1283	107	$ 16.81	$ 17.20	$ 17.60
	644	400	HPS	St Lights - Owned	1886	157	$ 26.53	$ 27.14	$ 27.76
*	645	125	MV	St Lights - Owned	656	55	$ 8.95	$ 9.16	$ 9.37
*	646	175	MV	St Lights - Owned	881	73	$ 12.13	$ 12.41	$ 12.70
*	647	250	MV	St Lights - Owned	1210	101	$ 16.75	$ 17.14	$ 17.53
	648	400	MV	St Lights - Owned	1906	159	$ 26.51	$ 27.12	$ 27.74
*	650	200	HPS	St Lights - Owned	1033	86	$ 14.63	$ 14.97	$ 15.31
	666	72	LED	St Lights - Rented	295	25	$ 13.27	$ 13.58	$ 13.89
	670	100	LED	St Lights - Rented	410	34	$ 15.44	$ 15.80	$ 16.16
	719	43	LED	St Lights - Owned	176	15	$ 2.43	$ 2.49	$ 2.55
*	720	200	HPS	Yard Lights - Rented	1033	86	$ 30.31	$ 31.01	$ 31.72
*	730	70	HPS	Yard Lights - Rented	389	32	$ 15.25	$ 15.60	$ 15.96
*	731	100	HPS	Yard Lights - Rented	553	46	$ 19.36	$ 19.81	$ 20.27
*	732	150	HPS	Yard Lights - Rented	799	66	$ 27.69	$ 28.33	$ 28.98
	733	250	HPS	Yard Lights - Rented	1283	106	$ 37.65	$ 38.52	$ 39.41
	734	400	HPS	Yard Lights - Rented	1886	157	$ 44.04	$ 45.05	$ 46.09
*	735	125	MV	Yard Lights - Rented	656	54	$ 15.10	$ 15.45	$ 15.81
*	736	175	MV	Yard Lights - Rented	881	73	$ 19.20	$ 19.64	$ 20.09
*	737	250	MV	Yard Lights - Rented	1210	100	$ 26.71	$ 27.32	$ 27.95
*	738	400	MV	Yard Lights - Rented	1906	158	$ 34.12	$ 34.90	$ 35.70
*	740	70	HPS	Yard Lights - Owned	389	32	$ 5.99	$ 6.13	$ 6.27
*	741	100	HPS	Yard Lights - Owned	553	46	$ 7.90	$ 8.08	$ 8.27
	742	150	HPS	Yard Lights - Owned	779	65	$ 10.62	$ 10.86	$ 11.11
	743	250	HPS	Yard Lights - Owned	1283	107	$ 16.81	$ 17.20	$ 17.60
	744	400	HPS	Yard Lights - Owned	1886	157	$ 26.53	$ 27.14	$ 27.76
	745	125	MV	Yard Lights - Owned	656	55	$ 8.95	$ 9.16	$ 9.37
	746	175	MV	Yard Lights - Owned	881	73	$ 12.13	$ 12.41	$ 12.70
	747	250	MV	Yard Lights - Owned	1210	101	$ 16.75	$ 17.14	$ 17.53
	748	400	MV	Yard Lights - Owned	1906	159	$ 26.51	$ 27.12	$ 27.74
	749	180	LPS	Yard Lights - Owned	869	72	$ 12.38	$ 12.66	$ 12.95
	750	200	HPS	Yard Lights - Owned	1033	86	$ 14.63	$ 14.97	$ 15.31
	751	135	LPS	Yard Lights - Owned	730	61	$ 9.85	$ 10.08	$ 10.31
	752	90	LPS	Yard Lights - Owned	521	43	$ 6.91	$ 7.07	$ 7.23
	753	250	Flood	Yard Lights - Rented	1283	107	$ 35.92	$ 36.75	$ 37.60
	754	400	Flood	Yard Lights - Rented	1886	157	$ 44.73	$ 45.76	$ 46.81
	755	250	Halide	Yard Lights - Rented	1148	95	$ 37.84	$ 38.71	$ 39.60
	756	400	Halide	Yard Lights - Rented	1878	156	$ 46.57	$ 47.64	$ 48.74
	757	1000	Halide	Yard Lights - Rented	4346	362	$ 79.93	$ 81.77	$ 83.65
	758	70	Halide	St Lights - Owned	390	32	$ 5.40	$ 5.52	$ 5.65
	759	100	Halide	St Lights - Owned	533	44	$ 7.39	$ 7.56	$ 7.73
	760	175	Halide	St Lights - Owned	894	74	$ 12.40	$ 12.69	$ 12.98
	761	250	Halide	St Lights - Owned	1148	95	$ 15.91	$ 16.28	$ 16.65
	762	400	Halide	St Lights - Owned	1878	156	$ 26.01	$ 26.61	$ 27.22
	763	1000	Halide	St Lights - Owned	4346	362	$ 60.20	$ 61.58	$ 63.00
	764	100	LED	St Lights - Owned	410	34	$ 5.68	$ 5.81	$ 5.94
	765	150	Halide	St Lights - Owned	759	63	$ 10.51	$ 10.75	$ 11.00
	766	72	LED	St Lights - Owned	295	25	$ 4.08	$ 4.17	$ 4.27
	775	107	LED	St Lights - Owned	438	37	$ 6.07	$ 6.21	$ 6.35
	780	143	LED	St Lights - Owned	586	49	$ 8.12	$ 8.31	$ 8.50
	785	175	LED	St Lights - Owned	718	60	$ 9.93	$ 10.16	$ 10.39

* These charges are applicable to existing fixtures only.

Maritime Electric Company, Limited
Schedule of Rates

		March 1, 2016	March 1, 2017	March 1, 2018
610	Pole Rental -Wood	$ 4.38	$ 4.38	$ 4.38
611	Pole Rental -Concrete	$ 7.96	$ 7.96	$ 7.96
	Unmetered Rates (based on 100 watt fixture)			
810	8 Hour Lighting per kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
820	12 Hour Lighting per kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
830	24 Hour Lighting per kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category		
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week			
234	Customer Owned Outdoor Recreational Lighting			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 5,000 kWh	$ 0.1661	$ 0.1699	$ 0.1738
	Energy Charge per kWh for balance of kWh	$ 0.1020	$ 0.1043	$ 0.1067
	Short Term Unmetered Rates	Currently no customers in this rate category		
	Energy Charge:			
	per kWh of estimated consumption	$ 0.1661	$ 0.1699	$ 0.1738

Connection Charge:	Three-Phase
A. Connecting to existing secondary voltage	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Three-Phase
(1) Up to and including 10 kVA	$209.17
(2) 11 kVA to 15 kVA	$301.01
(3) 16 kVA to 25 kVA	$336.64
(4) 26 kVA to 37 kVA	$336.64
(5) 38 kVA to 50 kVA	$336.64
(6) 51 kVA to 75 kVA	$523.96
(7) 76 kVA to 125 kVA	$555.59
(8) Above 125 kVA	$594.94

Maritime Electric Company, Limited
Schedule of Inputs

	2016	2017	2018
Summary of Forecast NPP and Sales			
Net Purchased & Produced (kWh)	1,287,845,600	1,314,420,900	1,340,478,000
Sales (kWh)			
Residential	563,660,000	580,352,000	596,667,000
General Service	391,720,000	394,887,000	397,870,000
Large Industrial	131,336,000	131,704,000	132,086,000
Small Industrial	98,933,000	103,731,000	108,397,000
Street Lighting	5,670,000	5,390,000	5,109,000
Unmetered	2,460,000	2,478,000	2,491,000
	1,193,779,000	1,218,542,000	1,242,620,000
ECAM Base Rate per kWh (Effective March 1)	0.08605	0.08988	0.09161
RORA Rebate per kWh (Effective March 1)	0.00410	0.00473	0.00345
Capital Structure (Average)			
Debt	59.10%	60.00%	60.00%
Equity	40.90%	40.00%	40.00%
	100.00%	100.00%	100.00%
Return on Average Common Equity	9.35%	9.35%	9.35%
Rate Base (Average)	340,818,000	359,398,000	374,717,000
Return on Average Rate Base	7.43%	7.17%	7.05%
Average Short Term Financing Rate	2.9%	3.3%	3.5%
Annual Capital Expenditures	30,660,000	29,399,000	30,815,000
Summary of Revenues and Expenses			
Basic Rate Revenue			
Residential	92,947,000	97,759,000	102,449,000
General Service	60,012,000	62,138,000	64,033,000
Large Industrial	10,854,000	11,208,000	11,448,000
Small Industrial	12,603,000	13,494,000	14,331,000
Street Lighting	2,137,000	2,101,000	2,022,000
Unmetered	397,000	414,000	422,000
	178,950,000	187,114,000	194,705,000
Transmission Revenue	8,110,000	12,380,000	13,963,000
Miscellaneous Revenue	1,627,000	2,025,000	1,953,000
Total Revenue	188,687,000	201,519,000	210,621,000
Operating Expenses			
Energy Costs	111,986,000	117,726,000	122,657,000
Distribution	8,176,000	8,727,000	8,968,000
Transmission - OATT (Cable)	-	4,133,000	5,590,000
Transmission - OATT (Other)	6,665,000	6,813,000	6,937,000
Corporate	10,094,000	10,484,000	10,783,000
Amortization - Fixed Assets & Other	21,139,000	22,397,000	23,650,000
Financing Expenses	12,388,000	12,433,000	12,645,000
Income Taxes	5,768,000	5,943,000	6,123,000
Net Earnings	12,471,000	12,863,000	13,268,000

APPENDIX B

Supplemental Information – 2016, 2017 and 2018 Inputs

APPENDIX B

Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 4-2 Rate of Return Adjustment (RORA) Payable to Customers ($)				
Year	RORA	Interest	Refunded to Customers	Balance Owing to Customers
2011	$ 1,874,268	$ -	$ -	$ 1,874,268
2012	2,239,130	57,166	-	4,170,564
2013	3,586,955	117,873	(648,556)	7,226,836
2014	3,674,728	205,812	(829,060)	10,278,316
2015	5,444,928	277,477	(843,956)	15,156,765
2016 (Forecast)	-	381,400	(4,505,900)	11,032,265
2017 (Forecast)	-	273,900	(5,893,000)	5,413,165
2018 (Forecast)	-	121,600	(4,706,300)	828,465
2019 (Jan - Feb Forecast)		6,000	(834,465)	-
Total	**$ 16,820,009**	**$ 1,441,228**	**$ (18,261,237)**	**$ -**

APPENDIX B
Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 5-1				
Cost of Purchased and Produced Energy per kWh ($)				
	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Cost of Purchased and Produced Energy per kWh	$ 0.08718	$ 0.08605	$ 0.08988	$ 0.09161

SCHEDULE 5-2				
Costs Recoveral From (Payable To) Customers ($)				
	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Costs Recoverable From (Payable To) Customers	$ 2,467,325	$ 1,453,000	$ 716,800	$ 278,900

APPENDIX B

Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 7-1				
Energy Sales (GWh)				
Measure	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Regression Analysis Growth	1,188.6	1,193.8	1,218.5	1,242.6
Two-year Average Growth	1,199.7	1,234.1	1,271.0	1,310.5
Year-To-Date Growth	1,188.7	1,212.8	1,240.2	1,271.1

SCHEDULE 7-2				
Energy Sales (GWh)				
Energy Sales (GWh)	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Residential	568.0	563.7	580.4	596.7
General Service I	377.2	381.0	383.6	386.3
General Service II	11.8	10.8	11.3	11.5
Large Industrial	130.1	131.3	131.7	132.1
Small Industrial	93.1	98.9	103.7	108.4
Street Lighing/Unmetered	8.4	8.1	7.8	7.6
Total Energy Sales	**1,188.6**	**1,193.8**	**1,218.5**	**1,242.6**
Growth Rate (%)				
Residential	4.91	(0.76)	2.96	2.81
General Service I	-	1.01	0.68	0.70
General Service II	25.53	(8.47)	4.63	1.77
Large Industrial	(8.51)	0.92	0.30	0.30
Small Industrial	4.72	6.23	4.85	4.53
Street Lighing/Unmetered	(2.33)	(3.57)	(3.70)	(2.56)
Overall Growth Rate	**1.79**	**0.44**	**2.07**	**1.98**

APPENDIX B

Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 8-2 Net Purchased and Produced Energy (GWh)	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Energy Sales	1,188.6	1,193.8	1,218.5	1,242.6
Company Use & System Losses	92.1	94.0	95.9	97.9
Total	**1,280.7**	**1,287.8**	**1,314.4**	**1,340.5**

SCHEDULE 8-3 Energy Supply by Source ($)	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Point Lepreau	$ 21,214,708	$ 19,856,100	$ 20,399,000	$ 20,253,900
EPA - Firm Energy Purchases	25,630,030	26,591,300	39,202,800	43,650,000
EPA - System Energy Purchases	31,432,598	31,754,600	20,547,500	19,816,900
Charlottetown Plant	3,777,430	3,509,000	4,040,600	3,182,500
Combustine Turbine #3	1,427,103	1,793,300	2,418,300	2,057,800
Borden-Carleton Plant	351,300	350,700	426,200	412,800
Energy Control Centre Operations	674,589	835,800	862,100	882,600
Wind	25,145,607	24,108,900	24,224,100	24,456,500
Ancillary Services	539,203	540,900	546,200	553,100
Other Purchases	1,253,080	1,384,500	1,788,300	2,450,000
NB Cable Interconnection Charges	-	-	3,264,900	4,417,000
Amortization of Deferred Charges	207,362	93,400	415,900	666,400
Total	**$ 111,653,010**	**$ 110,818,500**	**$ 118,135,900**	**$ 122,799,500**

SCHEDULE 8-4 Charlottetown Plant Operating Expenses ($) Description	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Buildings & Services	$ 516,581	$ 524,000	$ 551,900	$ 458,300
Plant Maintenance	869,366	1,559,800	1,188,700	1,641,800
Plant Operating	450,857	489,800	870,100	507,500
Superintendence	314,826	276,600	287,900	382,200
Generation Fuel & Plant Heating	1,625,800	658,800	1,142,000	192,700
Total	**$ 3,777,430**	**$ 3,509,000**	**$ 4,040,600**	**$ 3,182,500**

SCHEDULE 8-5 Combustine Turbine #3 Operating Expenses ($) Description	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Buildings & Services	$ 6,126	$ 6,100	$ 6,300	$ 6,500
Plant Maintenance	191,196	126,400	131,300	124,900
Plant Operating	66,974	19,700	20,700	17,800
Generation Fuel	1,162,807	1,641,100	2,260,000	1,908,600
Total	**$ 1,427,103**	**$ 1,793,300**	**$ 2,418,300**	**$ 2,057,800**

SCHEDULE 8-6 Borden-Carleton Plant Operating Expenses ($) Description	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Buildings & Services	$ 4,462	$ 3,600	$ 3,700	$ 3,800
Plant Operating	8,908	6,800	7,300	6,000
Plant Maintenance	204,398	133,200	139,100	123,300
Generation Fuel	133,532	207,100	276,100	279,700
Total	**$ 351,300**	**$ 350,700**	**$ 426,200**	**$ 412,800**

SCHEDULE 8-8 Energy Supply Expenses - Other ($) Description	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Insurance	$ 538,388	$ 561,400	$ 578,200	$ 595,500
Property Tax	198,506	210,100	216,400	222,900
Professional Development & Training	5,276	119,400	123,000	126,700
Total	**$ 742,170**	**$ 890,900**	**$ 917,600**	**$ 945,100**

APPENDIX B
Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 9-1 Transmission Expenses ($)				
Description	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Substations	$ 45,592	$ 55,400	$ 56,700	$ 58,200
Rights of Way	168,300	309,000	328,900	349,700
Line Maintenance	259,077	355,900	383,700	379,200
Line Control Devices	56,994	69,200	70,900	72,700
Engineering	108,086	110,600	119,900	123,500
Open Access Transmission Tariff	6,783,373	6,665,100	10,945,800	12,526,600
Total	**$ 7,421,422**	**$ 7,565,200**	**$ 11,905,900**	**$ 13,509,900**

SCHEDULE 9-2 Maritime Electric OATT Expenses ($)				
Description	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Network Service	$ 5,195,831	$ 5,681,300	$ 5,802,900	$ 5,914,200
Schedule 1	205,977	225,200	230,000	234,500
Schedule 2	333,044	364,200	372,000	379,100
Schedule 3C	13,610	-	-	-
Schedule 4	628,963	-	-	-
Schedule 9	74,928	74,900	74,900	74,900
Schedule 10	36,113	-	-	-
NB/Cable Interconnection Charges	-	-	4,133,300	5,590,300
OATT Operations	294,907	319,500	332,700	333,600
Total	**$ 6,783,373**	**$ 6,665,100**	**$ 10,945,800**	**$ 12,526,600**

SCHEDULE 9-3 Distribution Expenses ($)				
Description	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Substations	$ 100,532	$ 103,300	$ 106,200	$ 109,200
Rights of Way	1,323,757	1,328,900	1,671,200	1,711,400
Line Maintenance	1,580,751	1,867,700	1,908,400	1,973,800
Line Control Devices	70,016	84,000	86,400	88,800
Transformers	488,096	557,500	573,400	578,400
Meters	158,684	238,800	237,900	244,500
Communications Systems	204,550	207,500	213,100	218,800
Supervisory SCADA	106,764	121,700	125,000	128,400
Engineering	314,820	459,400	475,800	489,900
Total	**$ 4,347,970**	**$ 4,968,800**	**$ 5,397,400**	**$ 5,543,200**

SCHEDULE 9-4 Transmission & Distribution Expenses - Other ($)				
Description	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Insurance	$ 98,678	$ 99,900	$ 103,000	$ 106,200
Property Tax	1,927,775	2,113,600	2,177,000	2,242,300
Professional Development & Training	96,704	93,400	89,900	92,600
Total	**$ 2,123,157**	**$ 2,306,900**	**$ 2,369,900**	**$ 2,441,100**

APPENDIX B
Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 10-1				
General and Administrative Expenses ($)				
Description	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Customer Service and Meter Reading	$ 2,051,442	$ 2,234,200	$ 2,301,600	$ 2,299,500
Finance and Accounting	1,338,120	1,469,300	1,516,900	1,566,000
Corporate Communications and Public Affairs	431,934	457,100	477,200	491,500
Information Technology	420,868	512,500	527,900	543,800
Regulation	888,346	802,300	814,800	837,600
Directors' Fees	238,755	220,500	227,100	233,900
General Property - Tax & Maintenance	734,839	719,900	744,200	771,900
Corporate Services and Support	3,591,752	3,007,100	3,173,100	3,305,700
Total	**$ 9,696,056**	**$ 9,422,900**	**$ 9,782,800**	**$ 10,049,900**

APPENDIX B

Supplemental Information - 2016, 2017 and 2018 Inputs

Section 11.4 Summary				
Amortization Expense for Fixed Assets ($)				
Description	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Amortization - Fixed Assets	$ 15,886,668	$ 21,045,600	$ 21,981,400	$ 22,983,800

APPENDIX B
Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 12-1 Average Capital Structure (%)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Debt	57.0	59.1	60.0	60.0
Equity	43.0	40.9	40.0	40.0
Total	**100.0**	**100.0**	**100.0**	**100.0**

SCHEDULE 12-3 Dividends ($)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Regulated	$ 8,000,000	$ 8,000,000	$ 8,500,000	$ 8,500,000
Non-regulated	3,184,271	297,500	297,500	297,500
Total	**$ 11,184,271**	**$ 8,297,500**	**$ 8,797,500**	**$ 8,797,500**

SCHEDULE 12-4 Annual Interest Expense on Long-Term Debt ($)							
Issue Date	**Maturity Date**	**Principal Amount**	**Interest Rate (%)**	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
15-Aug-91	16-Aug-16	$ 12,000,000	11.500	$ 1,380,000	$ 805,000	$ -	$ -
7-Dec-93	7-Dec-18	15,000,000	8.550	1,282,500	1,282,500	1,282,500	1,175,625
22-Dec-00	22-Dec-25	15,000,000	7.570	1,135,500	1,135,500	1,135,500	1,135,500
15-Jan-97	15-Jan-27	15,000,000	8.625	1,293,750	1,293,750	1,293,750	1,293,750
3-Jul-96	3-Jul-31	20,000,000	8.920	1,784,000	1,784,000	1,784,000	1,784,000
2-Apr-08	2-Apr-38	60,000,000	6.054	3,632,400	3,632,400	3,632,400	3,632,400
5-Dec-11	5-Dec-61	30,000,000	4.915	1,474,500	1,474,500	1,474,500	1,474,500
1-Jul-16*	1-Jul-46	40,000,000	4.500	-	750,000	1,800,000	1,800,000
Total				**$ 11,982,650**	**$ 12,157,650**	**$ 12,402,650**	**$ 12,295,775**

* Forecast First Mortgage Bond Issue

Section 12.7 Summary Other Financing Costs ($)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Short Term Debt Charges	$ 665,789	$ 424,100	$ 216,900	$ 529,500
Allowance for Funds	$ (376,452)	$ (200,000)	$ (200,000)	$ (200,000)
Amortization of Financing Costs	$ 5,320	$ 6,300	$ 13,800	$ 19,600

SCHEDULE 12-7 Interest Coverage (Times)				
2014 Actual	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
2.5	2.5	2.4	2.5	2.5

APPENDIX B
Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 12-11 Calculation of Rate Base ($)				
Components	**2015 Actual**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Fixed Assets	$ 573,109,433	$ 599,638,800	$ 627,337,700	$ 656,502,600
Less: Capital Work in Progress	(5,098,313)	-	-	-
Less: Accumilated Amortization	(194,466,955)	(210,643,300)	(229,754,500)	(249,879,300)
Less: Contributions in Aid of Construction (net of amortization)	(25,439,503)	(24,720,700)	(23,990,900)	(23,250,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,750,370)	(15,660,600)	(17,740,096)	(19,994,491)
Less (Add): Costs Payble to (Recoverable from) Customers Post 2003	2,467,325	1,453,000	716,800	278,900
Add: Deferred Financing Costs	422,675	416,375	402,575	382,975
Add: Intangible Assets	4,105,909	4,650,000	4,750,000	4,800,000
Add: Deferred Demand Side Management Costs	100,000	1,755,900	3,631,824	5,338,208
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,768,817	1,675,400	1,581,976	1,488,592
Less (Add): Regulatory Liability OPEB	(5,013,477)	(3,319,500)	(1,694,700)	(69,900)
Less: Regulatory Liability - Rebates Payable to Customers	(18,473,243)	(14,611,800)	(9,261,000)	(4,950,100)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order	-	-	-	-
Plus: Working Capital Allowance Comprised of: - Inventory - Gross Operating Expenses X 3.6% (net of disallowed costs) Income Taxes Paid X 3.6%	5,163,885 4,887,951 304,488	5,700,000 4,891,700 322,600	5,800,000 5,331,400 136,700	5,850,000 5,566,400 123,100
Total Rate Base	**$ 330,088,622**	**$ 351,547,875**	**$ 367,247,779**	**$ 382,186,984**
Average Rate Base	**$ 325,724,871**	**$ 340,818,200**	**$ 359,397,800**	**$ 374,717,400**

SCHEDULE 12-12 Calculation of Return on Average Rate Base ($) & (%)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Total Revenue	$ 185,227,031	$ 188,687,300	$ 201,518,900	$ 210,620,700
Less: Operating Expenses (net of ECAM)	(137,822,160)	(136,249,800)	(147,181,200)	(154,201,300)
Less: Amortization of debt issue costs	(5,320)	(6,300)	(13,800)	(19,600)
	47,399,551	52,431,200	54,323,900	56,399,800
Less: Amortization Fixed Assets	(15,886,668)	(21,045,600)	(21,981,400)	(22,983,800)
Less: Amortization Deferred Charges	(207,362)	(93,400)	(415,900)	(666,400)
	(16,094,030)	(21,139,000)	(22,397,300)	(23,650,200)
Earnings Before Income Taxes and Financing Costs	31,305,521	31,292,200	31,926,600	32,749,600
Income Taxes	(6,001,467)	(5,976,200)	(6,160,100)	(6,350,300)
Earnings on Average Rate Base (interest expense excluded)	25,304,054	25,316,000	25,766,500	26,399,300
Rate Base - Year End Average	325,724,871	340,818,200	359,397,800	374,717,400
Actual/Requested Return on Average Rate Base (for rate making purposes)	7.77%	7.43%	7.17%	7.05%

APPENDIX B
Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 15-1 Schedule of Capital Expenditures ($)	2015 Actual *	2016 Forecast	2017 Forecast	2018 Forecast
Generation				
Charlottetown Plant	$ 451,154	$ 1,061,000	$ 1,035,000	$ 496,000
Borden-Carleton Plant	234,643	154,000	102,000	1,524,000
Transmission & Distribution				
Transmission	8,092,841	10,399,000	8,901,000	8,063,000
Distribution	16,132,068	17,538,000	18,010,000	19,207,000
Corporate	897,584	1,214,000	1,045,000	1,205,000
Sub-total	25,808,290	30,366,000	29,093,000	30,495,000
Allowance for Funds Used During Construction	376,452	200,000	200,000	200,000
General Expense Capitalized	458,433	494,000	507,000	521,000
Less: Contributions	(382,693)	(400,000)	(400,000)	(400,000)
Net Capital Expenditures	**$ 26,260,482**	**$ 30,660,000**	**$ 29,400,000**	**$ 30,816,000**

* 2015 includes $1,617,160 of carryover expenditures (net of contributions) approved in prior years.

SCHEDULE 15-2 Operating Expenses ($)	Schedule Reference	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Energy Supply Expenses	8-3	$ 111,653,010	$ 110,818,500	$ 118,135,900	$ 122,799,500
Energy Supply Expenses - Other	8-8	742,170	890,900	917,600	945,100
ECAM		2,042,375	370,000	(912,400)	(421,000)
Distribution	9-3	4,347,970	4,968,800	5,397,400	5,543,200
Transmission*	9-1	7,421,422	7,565,200	11,905,900	13,509,900
Trasmission & Distribution - Other	9-4	2,123,157	2,306,900	2,369,900	2,441,100
General & Administrative **	10-4	9,696,056	9,422,900	9,782,800	10,049,900
Total		$ 138,026,160	$ 136,343,200	$ 147,597,100	$ 154,867,700

* Includes OATT Expenses
** Excludes Fortis Inc. Administrative Charges

SCHEDULE 15-3 Effective Corporate Income Tax Rates ($)	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Effective Tax Rate	31.5	31.6	31.6	31.6

SCHEDULE 15-4 Revenue Requirement ($)	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Operating Expenses (Net of ECAM)*	$ 137,818,798	$ 136,249,800	$ 147,181,200	$ 154,201,300
Interest Expense (including amortization of Debt Issue Costs)	12,277,307	12,388,000	12,433,300	12,644,900
Amortization - Fixed Assets	15,886,668	21,045,600	21,981,400	22,983,800
Amorization - DSM Costs	113,962	-	322,500	573,000
Amortization - Lepreau Writedown	93,400	93,400	93,400	93,400
Income Tax Expense	6,001,467	5,976,200	6,160,100	6,350,300
Return on Average Rate Base**	13,035,429	12,934,300	13,347,000	13,774,000
Total	$ 185,227,031	$ 188,687,300	$ 201,518,900	$ 210,620,700

* Excluding Fortis Inc. Costs
** Before Disallowable Costs

SCHEDULE 15-5 Other Revenue($)	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
OATT				
Network Service	$ 5,195,831	$ 5,681,300	$ 5,802,800	$ 5,914,200
Schedule 1	299,619	297,100	302,000	306,500
Schedule 2	447,616	481,200	489,200	496,500
Schedule 3C	13,610	-	-	-
Schedule 4	745,913	-	-	-
Schedule 7	270,859	270,900	270,900	270,900
Schedule 8	1,084,305	1,051,100	1,053,700	1,056,300
Schedule 9	326,372	328,400	328,400	328,400
Schedule 10	12,602	-	-	-
NB Cable Interconnection Charges	-	-	4,133,300	5,590,300
Sub-total	8,396,727	8,110,000	12,380,300	13,963,100
Other				
Late Payment Charges	668,829	546,000	574,900	602,200
Connection Fees	468,221	466,400	491,700	514,500
Miscellaneous Revenue	633,167	612,700	957,800	835,700
Sub-total	1,770,217	1,625,100	2,024,400	1,952,400
Total Other Revenue	**$ 10,166,944**	**$ 9,735,100**	**$ 14,404,700**	**$ 15,915,500**

APPENDIX B

Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 15-6				
Energy Sales by Class (Existing Basic Rates)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Energy by Class - (GWh)				
Residential	568.0	563.7	580.4	596.7
General Service I	377.2	381.0	383.6	386.3
General Service II	11.8	10.8	11.3	11.5
Large Industrial	130.1	131.3	131.7	132.1
Small Industrial	93.1	98.9	103.7	108.4
Street Lighting	6.0	5.6	5.3	5.1
Unmetered	2.4	2.5	2.5	2.5
Total Energy Sales	**1,188.6**	**1,193.8**	**1,218.5**	**1,242.6**
Gross Revenue by Class - ($)				
Residential	$ 93,919,219	$ 93,208,500	$ 95,643,800	$ 98,028,000
General Service I	58,359,102	58,614,400	58,991,900	59,371,600
General Service II	1,691,477	1,583,300	1,653,500	1,692,200
Large Industrial	11,513,452	11,121,100	11,145,500	11,170,800
Small Industrial	12,179,360	12,645,000	13,156,100	13,652,200
Street Lighting	2,441,584	2,161,800	2,054,800	1,947,800
Unmetered	400,821	401,900	404,900	407,000
Total Gross Electric Revenue	**180,505,015**	**179,736,000**	**183,050,500**	**186,269,600**
Rate of Return Adjustment	(5,444,928)	-	-	-
Total Electric Revenue	**175,060,087**	**179,736,000**	**183,050,500**	**186,269,600**
Total Other Revenue	**10,166,944**	**9,735,100**	**14,404,700**	**15,915,500**
Total Revenue	**$ 185,227,031**	**$ 189,471,100**	**$ 197,455,200**	**$ 202,185,100**

SCHEDULE 15-7				
Energy Sales by Class (Proposed Basic Rates)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Energy by Class - (GWh)				
Residential	568.0	563.7	580.4	596.7
General Service I	377.2	381.0	383.6	386.3
General Service II	11.8	10.8	11.3	11.5
Large Industrial	130.1	131.3	131.7	132.1
Small Industrial	93.1	98.9	103.7	108.4
Street Lighting	6.0	5.6	5.3	5.1
Unmetered	2.4	2.5	2.5	2.5
Total Energy Sales	**1,188.6**	**1,193.8**	**1,218.5**	**1,242.6**
Gross Revenue by Class - ($)				
Residential	$ 93,919,219	$ 92,947,500	$ 97,758,600	$ 102,448,600
General Service I	58,359,102	58,434,200	60,443,000	62,256,200
General Service II	1,691,477	1,578,200	1,695,500	1,777,300
Large Industrial	11,513,452	10,854,300	11,208,400	11,448,200
Small Industrial	12,179,360	12,603,000	13,494,500	14,330,900
Street Lighting	2,441,584	2,137,500	2,100,500	2,021,600
Unmetered	400,821	397,500	413,700	422,400
Total Gross Electric Revenue	**180,505,015**	**178,952,200**	**187,114,200**	**194,705,200**
Rate of Return Adjustment	(5,444,928)	-	-	-
Total Electric Revenue	**175,060,087**	**178,952,200**	**187,114,200**	**194,705,200**
Total Other Revenue	**10,166,944**	**9,735,100**	**14,404,700**	**15,915,500**
Total Revenue	**$ 185,227,031**	**$ 188,687,300**	**$ 201,518,900**	**$ 210,620,700**

APPENDIX B

Supplemental Information - 2016, 2017 and 2018 Inputs

SCHEDULE 16-2				
Annual Cost for Rural Residential Customer (650kWh per Month/7,800 kWh per Year)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 323.04
Basic Energy Charge	1,034.28	1,029.60	1,072.50	1,099.02
ECAM Charge	(46.44)	16.06	9.26	4.48
Provincial Costs Recoverable	41.81	41.81	41.81	41.81
Cable Contingency Fund	2.11	2.11	2.11	2.11
RORA	(5.52)	(31.96)	(36.91)	(26.87)
Sub-total	1,349.28	1,380.66	1,411.81	1,443.59
HST	188.90	193.29	197.65	202.10
Total Annual Cost	**$ 1,538.18**	**$ 1,573.95**	**$ 1,609.46**	**$ 1,645.69**
Percentage Annual Increase (%)	**2.2%**	**2.3%**	**2.3%**	**2.3%**

* **Schedule 16-3** was included in the Application to highlight certain proposed rate adjustments to the General Service class as a result of the recommendations of the Cost Allocation Study. These class specific adjustments are not included in the Agreement and therefore this schedule is no longer considered pertinent evidence.

SCHEDULE 16-4				
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)				
	2015 Actual	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80	4,834.80	4,834.80
Basic Energy Charge	16,164.00	16,092.00	16,764.00	17,190.00
ECAM Charge	(714.41)	247.01	142.53	68.97
Provincial Costs Recoverable	643.20	643.20	643.20	643.20
Cable Contingency Fund	32.40	32.40	32.40	32.40
RORA	(84.87)	(491.68)	(567.81)	(413.42)
Sub-total	21,169.96	21,652.57	22,143.96	22,650.79
HST	2,963.79	3,031.36	3,100.15	3,171.11
Total Annual Cost	**$ 24,133.75**	**$ 24,683.93**	**$ 25,244.11**	**$ 25,821.90**
Percentage Annual Increase (%)	**2.2%**	**2.3%**	**2.3%**	**2.3%**

APPENDIX C

Schedule of Basic Fees, Rates and Charges (Section N)
March 1, 2016

Energy Cost Adjustment Mechanism

Application The following energy cost adjustment mechanism applies to all scheduled rates applicable to the sale of energy by Maritime Electric Company, Limited.

Energy Cost Adjustment Mechanism The energy charge applicable under all applicable rates will be subject to a rate adjustment when the cost of purchased and produced electricity increases or decreases from the base cost.

The forecast Base Rate Cost for purchased and produced electricity is $0.08605/kWh and may be adjusted as Ordered by the Commission.

Deferral of Increases or Decreases from the Base Cost The deferral of increases or decreases in purchased and produced electricity from the Base Cost shall be calculated at the end of each month as follows:

1. Determine the total cost of purchasing and producing electricity in the month including any amounts amortized to ECAM as Ordered by the Commission;
2. Determine the net kilowatt hours of purchased and produced energy in the month;
3. Multiply the quantity of net purchased and produced energy determined in (2) above by the forecast Base Rate Cost of $0.08605/KWh to determine the base cost of electricity;
4. Subtract the base cost of electricity determined in (3) above from the total cost of purchasing and producing electricity determined in (1) above to calculate the excess or deficiency of the cost of purchased or produced electricity from the base cost;
5. Add the excess (or deficiency) of the cost of purchased or produced energy calculated in (4) above to the corresponding excess (or deficiency) costs on the Balance Sheet.

Calculation of ECAM Rate Adjustment Applied to Customers' Bills The ECAM Rate Adjustment applied to Customers' bills shall be calculated as follows and applied to Customers' bills for not less than twelve months unless otherwise Ordered by the Commission.

6. Determine the total of the excess (or deficiency) costs on the Balance Sheet at the end of the third month proceeding the month in which the ECAM rate will be applied.
7. Determine the forecast total kilowatt hour sales for the twelve month period commencing with the month in which the ECAM rate will be applied.
8. Divide the amount calculated in (6) above by the amount calculated in (7) above to determine the ECAM rate adjustment required in cents per kilowatt hour sold and which will be applied to Customers' bills. Rate adjustment shall be calculated to the nearest three decimal places (five decimal places on the dollar).

* Application of the Energy Cost Adjustment Mechanism is subject to the terms and provisions of the Electric Power Act.

Residential Service Rate Schedule

Residential Urban That category of residential customers located in all incorporated cities, towns and villages with population over 2000 served by Maritime Electric.

Rate	***(Code 110)***
Service Charge:	$24.57 per Billing Period
Energy Charge:	13.56¢ per kWh for first 2000 kWh per Billing Period 10.79¢ per kWh for balance kWh per Billing Period

Residential Rural That category of residential customers located in all other areas not included under Residential Urban category served by Maritime Electric.

Rate	***(Code 130)***
Service Charge:	$26.92 per Billing Period
Energy Charge:	13.56¢ per kWh for first 2000 kWh per Billing Period 10.79¢ per kWh for balance kWh per Billing Period

Residential Seasonal That category of Residential Customers who require service to a dwelling other than a principal residence (e.g., summer cottages).

Rate	***(Code 131)***
Service Charge:	$26.92 per Billing Period
Energy Charge:	13.56¢ per kWh for first 2000 kWh per Billing Period 10.79¢ per kWh for balance kWh per Billing Period

Residential Seasonal Option Residential seasonal customers with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. Residential Seasonal customers whose 1 November to 31 May consumption exceeds this fifty percent (50%) shall be billed under the applicable residential service rate for the periods connected. Meters shall be read or estimated and bills shall be rendered for May, June, July, August, September and October.

Rate	***(Code 133)***
Service Charge:	$37.50 per Billing Period
Energy Charge:	13.56₵ per kWh for first 2000 kWh per Billing Period 10.79₵ per kWh for balance kWh per Billing Period

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Residential Service Rate Application Guidelines

Urban and Rural

Customers who use electricity for living purposes in any of the following:

- Dwellings;
- Dwelling out buildings; and
- Individually metered, self contained dwelling units within an apartment building.

In addition, the Residential Rate applies to:

- Services to farms and churches; and
- Service for the construction phase of a dwelling.

A premises providing lodging with nine (9) beds or less, including boarding and rooming houses, special care establishments, senior citizen homes, nursing homes, hostels and transition homes.

The combined usage of a dwelling and a business operation measured by one meter, where the connected load of the business operation, excluding space heating and air conditioning, is two (2) kilowatts or less.

Seasonal

Customers who use electricity for living purposes in a dwelling other than the customer's principal residence; e.g., summer cottage.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

General Service Rate Schedules

General Service That category of customers in all areas served by Maritime Electric who use electricity for purposes other than those specifically covered under *Residential, Small and Large Industrial, Street Lighting or Unmetered* Categories.

Billing Demand
The greater of the maximum kW demand or 90% of the maximum kVA demand in the billing period.

Rate	***(Code 232)***
Service Charge:	$24.57 per Billing Period
Demand Charge:	No charge for first 20 kW or less per Billing Period $13.43 per kW for balance kW per Billing Period
Energy Charge:	16.64¢ per kWh for first 5000 kWh per Billing Period 10.90¢ per kWh for balance kWh per Billing Period

General Service – Seasonal Operators Option General Service seasonal operators with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. General Service seasonal operators whose 1 November to 31 May consumption exceeds this fifty percent (50%) shall be billed under the applicable General Service rate for the periods connected. Meters shall be read or estimated and bills shall be rendered for May, June, July, August, September and October.

Rate	***(Code 233)***
Service Charge:	$24.57 per Billing Period
Demand Charge:	No charge for first 20 kW or less per Billing Period $13.43 per kW for balance kW per Billing Period
Energy Charge:	16.64¢ per kWh for first 5000 kWh per Billing Period 10.90¢ per kWh for balance kWh per Billing Period

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

General Service Rate Schedules – Cont'd

General Service II

Rate Class closed effective March 1, 2016

General Service Rate Application Guidelines

General Service

General Service rate applications include the following:

- Religious and charitable institutions, excluding churches;
- Service for the construction phase of any premises other than a dwelling;
- Dwellings providing lodging with more than nine (9) beds, including boarding and rooming houses, special care establishments, senior citizen homes, nursing homes, hostels and transition homes;
- Combined usage of a dwelling and a business operation measured by one meter, where the connected load of the business operation, excluding space heating and air conditioning, is greater than two (2) kilowatts;
- Bulk metered apartment buildings that combine the service to the dwelling units and/or the common use areas;
- Service to common areas in apartment buildings;
- Any business operation involving both manufacturing/processing and service/repair on which less than one half of the business volume is manufacturing/processing;
- Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one meter where the warehousing, storage and distribution load is greater than one half of the total electricity consumed;
- A retail or wholesale operation on a farm must install a separate meter to measure that retail/wholesale load;

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

General Service Rate Application Guidelines – Cont'd

- Water pumping, sewage lift stations, sewage lagoons, chlorinating plants and sewage treatment plants directly related to municipally owned water supplies or waste disposal systems are normally billed at General Service Rates. At the option of the customer, an Industrial Service Rate may be applied; and
- General Service seasonal operators with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. Examples of eligible facilities include seasonal tourist accommodations, attractions or eateries.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Small Industrial Rate Schedule

Small Industrial That category of customers who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of five (5) kilowatts.

Billing Demand
The greatest of:

- The monthly maximum kW demand;
- 90% of the monthly maximum kVA demand; or
- 5 kW.

As a result of installed metering, both the monthly maximum kW demand and 90% of the monthly maximum kVA demand noted above may not apply.

Rate ***(Code 320)***

Demand Charge: $7.46 per kW of billing demand per month

Energy Charge: 16.30¢ per kWh for first 100 kWh per kW of billing demand per month
8.26¢ per kWh for balance of kWh per month

To be eligible for service with a contracted demand, customers must sign the Contract for Electrical Service under Section C – Agreements and Forms.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Small Industrial Rate Application Guidelines

Industrial Rates apply to the following S.I.C. groups:

Division C Major group:
04 Logging Industry

Division D Major groups:
06 Mining Industries
07 Crude Petroleum and Natural Gas Industries
08 Quarry and Sand Pit Industries
09 Service Industries Incidental to Mineral Extraction

Division E Manufacturing Industries.

In addition:

Fish hatcheries qualify for this rate.

Any business operation involving both manufacturing/processing and service/repair in which more than one half of the business volume is manufacturing/processing.

Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one (1) meter where the manufacturing/processing load is greater than one half of the total electricity consumed.

A processing operation on a farm must install a separate meter to measure that processing load.

Customers whose demand is above 750 kW and less than 3000 kW may choose to be billed at the Small Industrial Rate but must meet certain conditions of the Large Industrial Rate; specifically, they must be metered at a primary voltage of 69 kV and own the step-down transformation from the primary service voltage or pay an equivalent rental charge.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule

Large Industrial

That category of customers in all areas served by Maritime Electric who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of 750 kW.

Billing Demand

The greatest of:

- The monthly maximum kW demand;
- 90% of the maximum kVA demand;
- 90% of the firm amount reserved in the contract for non-curtailable customers or 100% of the total contracted amount for curtailable customers;
- 90% of the maximum demand recorded during the current calendar year excluding April through November; or
- 90% of the lesser of the average demand recorded during the previous calendar year, or the previous calendar year excluding April through November.

Rates ***(Code 310)***

Demand Charge: $14.50 per kW of the billing demand per month

Energy Charge: 6.75¢ per kWh for all kWh per month

Declining Discount Firm Rate:

New facilities coming into service after April 1, 2000 or facilities that were substantially shut down as at October 1, 2000 are eligible for a declining discount on Demand Charges for the additional firm load.

The declining discount is available for five years to Customers who meet all of the following criteria:

i) the Customer is served directly from the Maritime Electric's transmission system;

ii) the additional firm load is at least 5,000 kW; and

iii) the Customer signs a five year agreement with Maritime Electric as the electricity supplier for the total load for the Customer's account at the site.

The declining discounts are:

Year	$/kW-month	Year	$/kW-month
1	$5.39	4	$2.16
2	$4.30	5	$1.08
3	$3.23	6	$0.00

The declining discounts are not available for loads that get incentive rate credits or if the Customer is in arrears at the time of application for the declining discount.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Start-up Rate

Large Industrial customers starting new operations or expanding existing operations may request a start-up rate for a period not exceeding six (6) consecutive months.

When the new load is the result of expansion, the customer has the option to request the start-up for the total firm load at that location. The request must be submitted in writing to Maritime Electric.

To qualify, the customer must agree to reduce the load for which the start-up rate applies within ten (10) minutes of a request from Maritime Electric. The reduction will be to a level stipulated by Maritime Electric. Load reductions will normally be requested when the in-province load is expected to exceed Maritime Electric's supply capability.

Maritime Electric estimates the applicable start-up rate and makes retroactive adjustments based on the customer's actual cost per kWh, which is the aggregate of demand and energy charges, established during the six month period following the start-up period.

The start-up rate will be calculated so that the resulting cost to the customer is the higher of:

- 10.01¢ per kWh, or
- Customer's lowest monthly aggregate cost per kWh in the six months following the start-up period.

The start-up rate period may be extended up to five years for new facilities having a firm load of 5,000 kilowatts or more that are served directly off the transmission system and that Maritime Electric considers to be a new industrial technology. This provision expires on March 31, 2008. In such cases, the firm load of the Customer will not be subject to interruption and the cost of the new firm load will be the lower of (i) Customers actual cost based on usage and applicable rates, or (ii) 9.49¢ per kWh.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Interruptible Energy Charge

Maritime Electric will supply interruptible energy in excess of the demand reserved for the Customer up to the amount of the Customer's unused generation capability, if such energy is available at the Delivery Point, and can be produced with available Maritime Electric Facilities over and above the requirement of other firm commitments of Maritime Electric. The rate will be based on Maritime Electric's incremental cost of providing such energy.

Surplus Energy Charge

To qualify for new Surplus Energy, the Customer must sign a minimum three-year contract with Maritime Electric as its sole electricity supplier. Surplus Energy is supplied only if it can be provided with available Maritime Electric Facilities over and above the requirement of other firm commitments of Maritime Electric. The Customer must interrupt Surplus Energy use within ten (10) minutes of a request from Maritime Electric. Customers can purchase Surplus Energy for load additions of 2,000 kilowatts or more.

Customers will be required to interrupt Surplus Energy to meet Maritime Electric financially firm export obligations. When Surplus Energy is interrupted to meet financially firm export obligations, the Customer is reimbursed 50 percent of the cost of the replacement energy that Maritime Electric would have otherwise incurred to supply the export sales.

Customers who fail to interrupt will be billed an additional charge which is the higher of:

(i) two times the monthly demand charge per kilowatt for the Large Industrial rate classification multiplied by the kilowatts that were not interrupted plus any incremental cost of supplying the energy, or
(ii) the costs incurred by Maritime Electric for replacement energy to supply financially firm export obligations.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Surplus Energy Charge (continued)

Up to March 2001, Customers can purchase Surplus Energy for load additions of 2000 kW or more. The total annual sales are limited to 500 million kilowatthours. Because of the limited amount of available Surplus Energy, preference will be given to the Customers who sign a power purchase contract with Maritime Electric until March 2001.

This Surplus Energy is supplied only if it can be provided with available Maritime Electric Facilities. The Customer must interrupt Surplus Energy use within 10 minutes of a request from Maritime Electric. The rate will be based on Maritime Electric's incremental cost of providing such energy.

Pricing of Interruptible And Surplus Energy

The price is based on Maritime Electric's incremental cost of providing such energy. Incremental cost is defined as Maritime Electric's incremental generation or purchased power cost after supplying in-province firm load and other firm supply commitments.

Interruptible and Surplus Energy price will be:

On peak price = incremental cost during on peak hours +1.96¢/kWh.
Off peak price = incremental cost during off peak hours +0.90¢/kWh.

The on peak period is defined as 0800 to 2400 hours Atlantic Prevailing Time on all weekdays, except statutory holidays in Prince Edward Island. All other hours are considered to be off peak.

Maritime Electric will provide a week ahead forecast and day ahead firm quotes of the on and off peak prices to be paid by the customer.

Schedulable Energy

To qualify for Schedulable Energy, the Customer must sign a minimum five-year contract with Maritime Electric as its sole electricity supplier. Schedulable Energy is supplied only if it can be provided with available Maritime Electric facilities over and above the requirement of other firm commitments, including financially firm export obligations of Maritime Electric. The Customer must interrupt Schedulable Energy use within ten (10) minutes of a request from Maritime Electric, or arrange for a third party supply.

Customers, who are serviced directly from Maritime Electric's transmission system, can purchase Schedulable Energy for load additions of 10,000 kilowatts or more up to March 31, 2008.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Schedulable Energy (continued)

Customers who fail to interrupt will be billed an additional charge which is the higher of:

(i) two times the monthly demand charge per kilowatt for the Large Industrial rate classification multiplied by the kilowatts that were not interrupted plus any incremental cost of supplying the energy, or
(ii) the costs incurred by Maritime Electric for replacement energy to supply financially firm export obligations.

The price is based on Maritime Electric's incremental cost of providing such energy. Incremental cost is defined as Maritime Electric's incremental generation or purchased power costs after supplying in-province firm load and other firm supply commitments.

Pricing of Schedulable Energy

Schedulable Energy price will be:

On peak price = incremental cost during on peak hours +1.96¢/kWh.
Off peak price = incremental cost during off peak hours +0.90¢/kWh.

The on peak period is defined as 0800 to 2400 hours Atlantic Prevailing Time on all weekends, except statutory holidays in Prince Edward Island. All other hours are considered to be off peak.

Maritime Electric will provide a week ahead forecast and day ahead firm quotes of the on and off peak prices to be paid by the Customer. When Maritime Electric has insufficient generation to supply its loads, the price of Schedulable Energy will be quoted and updated on an hourly basis.

Schedulable Energy Customers can arrange for a third party outside of Prince Edward Island to supply energy to Maritime Electric. In such an event, Maritime Electric would pay the supplier 0.075¢/kWh less than the incremental cost used in determining the price of Schedulable Energy and the Customer would still pay Maritime Electric the full price of Schedulable Energy including the adders.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Rental Charges

At the customer's request, Maritime Electric will supply, own and maintain the substation facilities from the high voltage switches to the low voltage terminals of the step-down transformers, provided such transformation satisfies Maritime Electric Standards. The charge for such rental facilities is $1^5/_6\%$ per month of the installed costs. The Customer will supply the low voltage switch gear, concrete substation foundation pads and necessary protective fencing.

Losses Charge

At the discretion of Maritime Electric, electricity may be supplied at a primary service voltage between 4 kV and 25 kV. In such cases, the monthly demand and energy consumption will be increased by 1½% to compensate for transformation losses.

Transformation Charge

When a customer is provided service at voltages less than 69 kV, the customer will also be charged an "equivalent kVA rental" charge equal to $1^5/_6\%$ per month of the costs of the equivalent substation kVA utilized by the Customer's electrical load. The equivalent kVA charge is the Customer's kVA demand multiplied by $1.25 per kVA per month.

Contracts

A customer supplied at the Large Industrial Rate is required, and is deemed, to have entered a firm contract providing for the payment of the rate, for an initial term of five (5) years, in the case of a customer considered by Maritime Electric to be a new customer, and for an initial term of one year for a customer considered by Maritime Electric to be an existing customer. The contract will continue thereafter on a firm basis subject to termination by either the customer or Maritime Electric at the end of the initial term, or any date thereafter by either party giving at least twelve month's notice in writing.

When a Customer's operations are jeopardized because of a failure of its electricity generating equipment, the Customer can apply to suspend any portion of its curtailable power contract and/or firm up all or part of interruptible purchases for a period of at least six months and not more than one year.

Metering

The metering point shall be at or near the transmission line terminals (69 kV).

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Application Guidelines

Industrial Rates apply to the following S.I.C. groups:

Division C Major Group:
04 Logging Industry

Division D Major Groups:
06 Mining Industries
07 Crude Petroleum and Natural Gas Industries
08 Quarry and Sand Pit Industries
09 Service Industries Incidental to Mineral Extraction

Division E, Manufacturing Industries.

In addition:

Any business operation involving both manufacturing/processing and service/repair in which more than one half of the business volume is manufacturing/processing.

Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one (1) meter where the manufacturing or processing load is greater than one half of the total load.

Customers whose demand is above 750 kW and less than 3000 kW may choose to be billed at the Small Industrial Rate but must meet certain conditions of the Large Industrial Rate; specifically, they must be metered at a primary service voltage of 69 kV and own the step-down transformation from the delivery voltage or pay an equivalent rental charge.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Wholesale Rate Schedule

Application The City of Summerside Electric Department.

Long Term Contract: The Wholesale Customer agrees to enter into a contract with Maritime Electric for a period not less than 10 years.

Rate	***(Code 340)***
Demand Charge:	$15.51 per kW per month
Energy Charge:	9.11¢ per kWh for all kWh in the month

Short Term Contract: The Wholesale Customer agrees to enter into a contract with Maritime Electric for a period not less than 1 year.

Rate	***(Code 330)***
Demand Charge:	$16.79 per kW per month
Energy Charge:	9.29¢ per kWh for all kWh in the first block per month 7.73¢ per kWh for balance of kWh in the month

First Energy Block Determination Set each year on 1 April based on the minimum monthly energy purchases that would have been required from Maritime Electric during the previous year period of 1 April to 31 March, assuming normalized generation from the customer's generating facilities.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Unmetered Rate Schedules

Unmetered Service That category of customers in all areas served by Maritime Electric requiring Unmetered Service.

Rate

Minimum Charge: $11.67 per month

Energy Charge: 16.61¢ per kWh of estimated consumption

Rate Codes: ***810 – 8 hour***
820 – 12 hour
830 – 24 hour

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Unmetered Rate Application Guidelines

Services for which electricity consumption is uniform and easily estimated.

Services where metering is not considered practical by Maritime Electric.

Specific applications of the Unmetered Rates include:

- Traffic control lights;
- Self – contained sign lighting;
- Architectural flood lighting;
- Decorative lighting;
- Carrier repeaters;
- Radio transmitters;
- Telephone booths;
- Range lights;
- Airport runway lights;
- Highway traffic counters; and
- CATV power supply units.

Estimating Consumption

Electricity consumption is estimated by multiplying the connected load in watts times the hours of usage. For example, a photoelectrically controlled 100 watt sign light operates approximately 12 hours per day, has an estimated annual consumption calculated as follows:

100 watts x 12 hours x 365 days = 438,000 watt-hours or 438 kWh per year.

If conditions are such as to cause reasonable doubt concerning the connected load, recording equipment will be installed to determine the kW connected load.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Miscellaneous Rate Schedules

Air Raid and Fire Sirens (unmetered)

Customer is charged $4.52 per month per HP of nameplate rating.
(Code 840)

Outdoor Christmas Lighting

Customer is charged 5.77¢ per watt of connected load per week. The minimum charge is for a period of one (1) week.
(Code 850)

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Short Term Unmetered Rate Schedule

That category of customers in all areas served by Maritime Electric requiring single-phase and three-phase installations and connected for no longer than one (1) month. The installation will not be metered.

Rate

Connection Charge:	Single-Phase	Three-Phase
A. Connecting to existing Secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	-	$594.94

Energy Charge:
16.61¢ per kWh of estimated consumption

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Short Term Unmetered Rate Application Guidelines

Available to serve such events as carnivals, bazaars and unmetered installations.

Connected for no longer than one (1) month.

When the service exceeds one month, the installation will be billed and the remaining time considered as a new installation.

When meters are involved, and not disconnected, a reading will be taken and the kilowatt hours noted for record purposes only.

When poles or additional equipment other than the transformer installation are required, the installation and removal charges will be estimated and collected before work commences. Customers who have a credit history, acceptable to Maritime Electric, may be billed using a Customers Contribution Estimate.

Estimating Consumption

Electricity consumption is estimated by multiplying the connected load in kW (or kVA times 0.9), times the hours of usage. For example, a carnival with a connected load of 25 kVA operates 12 hours per day for 10 days has an estimated consumption calculated as follows:

25 kVA x 0.9 power factor x 12 hours x 10 days = 2,700 kWh.

If conditions are such as to cause reasonable doubt concerning the connected load, recording equipment will be installed to determine the kVA connected load.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Rental Facility Rate Schedules

Area Lighting This rate applies to customers renting area lighting from Maritime Electric for a minimum of 12 consecutive months.

Rate

Luminaires:

Lamp Wattage	Mean Output (Lumens)	($) Rate Per Year	($) Rate Per Month	Rate Code	Annual kWhs
Mercury Vapour					
*125 Watt	5300	181.20	15.10	735	656
*175 Watt	7500	230.40	19.20	736	881
*250 Watt	11100	320.52	26.71	737	1210
*400 Watt	19800	409.44	34.12	738	1906
High Pressure Sodium					
*70 Watt	5500	183.00	15.25	730	389
*100 Watt	8500	232.32	19.36	731	553
*150 Watt	14400	332.28	27.69	732	799
*200 Watt	19800	363.72	30.31	720	1033
250 Watt	27000	451.80	37.65	733	1283
400 Watt	45000	528.48	44.04	734	1886
High Pressure Sodium Floodlight					
250 Watt	-	431.04	35.92	753	-
400 Watt	-	536.76	44.73	754	-
Metal Halide Floodlight					
250 Watt	-	454.08	37.84	755	-
400 Watt	-	558.84	46.57	756	-
1000 Watt	-	959.16	79.93	757	-

Poles:

Wood Pole			4.38	610	-
Concrete Pole			7.96	611	-

*These charges are applicable to existing fixtures only.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Rental Facility Rate Schedules - Cont'd

Street Lighting That category of customers renting street lighting from Maritime Electric.

Rate

Luminaires:

Lamp Wattage		Mean Output (Lumens)	($) Rate Per Year	($) Rate Per Month	Rate Code	Annual kWhs
Mercury Vapour						
*125 Watt		5300	181.20	15.10	635	656
*175 Watt		7500	230.40	19.20	636	881
*250 Watt		11100	320.40	26.70	637	1210
*400 Watt		19800	447.12	37.26	638	1906
High Pressure Sodium						
70 Watt	Lantern	5500	672.72	56.06	639	389
*70 Watt		5500	183.00	15.25	630	389
*100 Watt		8500	232.80	19.40	631	553
*150 Watt		14400	332.28	27.69	632	799
*200 Watt		19800	397.80	33.15	620	1033
250 Watt		27000	451.80	37.65	633	1283
400 Watt		45000	528.48	44.04	634	1886
LED Lighting						
43 Watt		-	138.36	11.53	619	176
50 Watt		-	143.28	11.94	625	205
72 Watt		-	159.24	13.27	666	295
100 Watt		-	185.28	15.44	670	410

*These charges are applicable to existing fixtures only.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Rental Facility Rate Schedules - Cont'd

Pole That category of customers renting poles from Maritime Electric.

Rate

The rental rate for poles is:

	($) Rate Per Pole Per Year	Rate Code
Wood pole	52.57	610
Concrete pole	95.48	611

Customer Facility Rate Schedule

Customer Owned Street and Area Lighting

That category of customers owning street and area lighting.

Rate Lamp Wattage	($) Per Year	($) Per Month	Rate Code St. Lt.	Rate Code Yd. Lt.	Annual kWhs
Incandescent					
100 Watt	72.24	6.02	-	-	-
200 Watt	145.56	12.13	-	-	-
300 Watt	217.56	18.13	-	-	-
500 Watt	349.08	29.09	-	-	-
Mercury Vapour					
100 Watt	87.36	7.28	-	-	-
125 Watt	107.40	8.95	645 *	745	656
175 Watt	145.56	12.13	646 *	746	881
250 Watt	201.00	16.75	647 *	747	1210
400 Watt	318.12	26.51	648	748	1906
700 Watt	541.44	45.12	-	-	-
1000 Watt	768.96	64.08	-	-	-
Low Pressure Sodium					
90 Watt	82.92	6.91	752	752	-
135 Watt	118.20	9.85	751	751	-
180 Watt	148.56	12.38	749	749	869
High Pressure Sodium					
70 Watt	71.88	5.99	640 *	740 *	389
100 Watt	94.80	7.90	641 *	741 *	553
150 Watt	127.44	10.62	642 *	742	779
200 Watt	175.56	14.63	650 *	750	1033
250 Watt	201.72	16.81	643	743	1283
400 Watt	318.36	26.53	644	744	1886
1000 Watt	763.44	63.62	-	-	-
Metal Halide Lighting					
70 Watt	64.80	5.40	-	758	390
100 Watt	88.68	7.39	-	759	533
150 Watt	126.12	10.51	-	765	759
175 Watt	148.80	12.40	-	760	894
250 Watt	190.92	15.91	-	761	1148
400 Watt	312.12	26.01	-	762	1878
1000 Watt	722.40	60.20	-	763	4346
LED Lighting					
43 Watt	29.16	2.43	719	-	176
72 Watt	48.96	4.08	766	-	295
100 Watt	68.16	5.68	764	-	410
107 Watt	72.84	6.07	775	-	438
143 Watt	97.44	8.12	780	-	586
175 Watt	119.16	9.93	785	-	718

*** These charges are applicable to existing fixtures only.**

Customer Facility Rate Schedule

Customer Owned Street and Area Lighting

The above charges apply to photocontrolled lights operating from dusk to dawn. The energy charges for lights operating from dusk to 1:30 a.m. and controlled by a time switch shall be 50% of the above rates.

Customers may request service for a customer owned street and area lighting fixture other than those categories listed above provided the fixture meets current electrical standards and is approved for installation by Maritime Electric. The interim rate for these new fixtures will be calculated using the formula below, as approved by IRAC.

$$\text{Basic Rate} = \frac{4{,}100 \text{ hrs} \times W/1000 \times U}{12 \text{ months}}$$

Where:

4,100 hours	=	the number of hours the fixture is on during the year
W	=	total wattage of the fixture, ballast and any other apparatus associated with the fixture
U	=	the basic Un-metered Service energy rate from Section N-17 of the approved tariff.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Customer Facility Rate Schedule - Cont'd

Customer Owned Outdoor Recreational Lighting

That category of customer owning metered outdoor lighting which operates only during the period April through November.

Rate

Service Charge: $24.57 billing period
Energy Charge: 16.61¢ per kWh for first 5000 kWh per billing period
10.20¢ per kWh for balance kWh per billing period

The above rate is available to customers with outdoor recreation lighting. Examples of customers on this rate include: baseball parks, soccer fields and tennis courts. Customers who have non-lighting requirements on the same service can also qualify for this rate if the connected non-lighting load is less than 20 kilowatts.

Customers on this rate who use electricity during December through March will be assessed demand charges for each month, including the preceding April through November, in which electricity is used. The demand charges will be assessed at the General Service I Rate. Failure to pay demand charges will result in the customer being placed on the General Service I Rate.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Open Access Transmission Tariff

This rate applies to eligible customers requiring transmission services. An eligible customer is:

(i) any electric utility (including the transmission provider), wholesale customer or any person generating electric energy for sale or resale outside of Prince Edward Island.

Application Eligible customers requesting transmission services must apply in writing and request services for a minimum 12 month period.

Transmission Services Include
Transmission Access and Capacity
Scheduling, System Control and Dispatch Service
Reactive Supply and Voltage Control

Billing Procedure Within a reasonable time after the first day of each month, the transmission provider or its designated agent shall submit an invoice to the transmission customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the transmission customer within 20 calendar days of receipt. All payments shall be made in immediately available funds payable to the transmission provider.

Rate **(Code XXX)**
The rates charged will be equal to 95% of those under the New Brunswick Power Tariff as amended from time to time.

Energy Cost Adjustment Mechanism: This rate is not subject to the Energy Cost Adjustment Mechanism.

Schedule of "Adjusted Rates"

Maritime Electric Company Limited
Applied to Bills Effective March 1, 2016

Rate Code			Rates
110	**Residential Urban**		
	Service Charge	$	24.57
	Energy Charge per kWh for first 2,000 kWh	$	0.1356
	Energy Charge per kWh for balance kWh	$	0.1079
130	**Residential Rural**		
	Service Charge	$	26.92
	Energy Charge per kWh for first 2,000 kWh	$	0.1356
	Energy Charge per kWh for balance kWh	$	0.1079
131	**Residential Seasonal**		
	Service Charge	$	26.92
	Energy Charge per kWh for first 2,000 kWh	$	0.1356
	Energy Charge per kWh for balance of kWh	$	0.1079
133	**Residential Seasonal Option**		
	Service Charge	$	37.50
	Energy Charge per kWh for first 2,000 kWh	$	0.1356
	Energy Charge per kWh for balance of kWh	$	0.1079
232	**General Service**		
	Service Charge	$	24.57
	Demand Charge - per kW for first 20 kW	$	-
	Demand Charge - per kW for balance of kW	$	13.43
	Energy Charge per kWh for first 5,000 kWh	$	0.1664
	Energy Charge per kWh for balance of kWh	$	0.1090
233	**General Service - Seasonal Operators Option**		
	Service Charge	$	24.57
	Demand Charge - per kW for first 20 kW	$	-
	Demand Charge - per kW for balance of kW	$	13.43
	Energy Charge per kWh for first 5,000 kWh	$	0.1664
	Energy Charge per kWh for balance of kWh	$	0.1090
320	**Small Industrial**		
	Demand Charge - per kW	$	7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$	0.1630
	Energy Charge per kWh for balance of kWh	$	0.0826
310	**Large Industrial**		
	Demand Charge per kW	$	14.50
	Energy Charge per kWh	$	0.0675
340	**Long Term Contract**		
	Demand Charge per kW	$	15.51
	Energy Charge per kWh	$	0.0911
330	**Short Term Contract**		
	Demand Charge - per kW	$	16.79
	Energy Charge per kWh for all kWh in the first block	$	0.0929
	Energy Charge per kWh for balance of kWh in the month	$	0.0773

Schedule of "Adjusted Rates"

Maritime Electric Company Limited
Applied to Bills Effective March 1, 2016

	ge per kWh for f	Lamp Wattage	Type		kWh	Monthly kWh		Basic Rates
	619	43	LED	St Lights - Rented	176	15	$	11.53
*	620	200	HPS	St Lights - Rented	1033	86	$	33.15
	625	50	LED	St Lights - Rented	205	17	$	11.94
*	630	70	HPS	St Lights - Rented	389	32	$	15.25
*	631	100	HPS	St Lights - Rented	553	46	$	19.40
*	632	150	HPS	St Lights - Rented	799	66	$	27.69
	633	250	HPS	St Lights - Rented	1283	106	$	37.65
	634	400	HPS	St Lights - Rented	1886	157	$	44.04
*	635	125	MV	St Lights - Rented	656	54	$	15.10
*	636	175	MV	St Lights - Rented	881	73	$	19.20
*	637	250	MV	St Lights - Rented	1210	101	$	26.70
*	638	400	MV	St Lights - Rented	1906	158	$	37.26
	639	70	Lanterns	City Lanterns - Rented	389	32	$	56.06
*	640	70	HPS	St Lights - Owned	389	32	$	5.99
*	641	100	HPS	St Lights - Owned	553	46	$	7.90
*	642	150	HPS	St Lights - Owned	779	65	$	10.62
	643	250	HPS	St Lights - Owned	1283	107	$	16.81
	644	400	HPS	St Lights - Owned	1886	157	$	26.53
*	645	125	MV	St Lights - Owned	656	55	$	8.95
*	646	175	MV	St Lights - Owned	881	73	$	12.13
*	647	250	MV	St Lights - Owned	1210	101	$	16.75
	648	400	MV	St Lights - Owned	1906	159	$	26.51
*	650	200	HPS	St Lights - Owned	1033	86	$	14.63
	666	72	LED	St Lights - Rented	295	25	$	13.27
	670	100	LED	St Lights - Rented	410	34	$	15.44
	719	43	LED	St Lights - Owned	176	15	$	2.43
*	720	200	HPS	Yard Lights - Rented	1033	86	$	30.31
*	730	70	HPS	Yard Lights - Rented	389	32	$	15.25
*	731	100	HPS	Yard Lights - Rented	553	46	$	19.36
*	732	150	HPS	Yard Lights - Rented	799	66	$	27.69
	733	250	HPS	Yard Lights - Rented	1283	106	$	37.65
	734	400	HPS	Yard Lights - Rented	1886	157	$	44.04
*	735	125	MV	Yard Lights - Rented	656	54	$	15.10
*	736	175	MV	Yard Lights - Rented	881	73	$	19.20
*	737	250	MV	Yard Lights - Rented	1210	100	$	26.71
*	738	400	MV	Yard Lights - Rented	1906	158	$	34.12
*	740	70	HPS	Yard Lights - Owned	389	32	$	5.99
*	741	100	HPS	Yard Lights - Owned	553	46	$	7.90
	742	150	HPS	Yard Lights - Owned	779	65	$	10.62
	743	250	HPS	Yard Lights - Owned	1283	107	$	16.81
	744	400	HPS	Yard Lights - Owned	1886	157	$	26.53
	745	125	MV	Yard Lights - Owned	656	55	$	8.95
	746	175	MV	Yard Lights - Owned	881	73	$	12.13
	747	250	MV	Yard Lights - Owned	1210	101	$	16.75
	748	400	MV	Yard Lights - Owned	1906	159	$	26.51
	749	180	LPS	Yard Lights - Owned	869	72	$	12.38
	750	200	HPS	Yard Lights - Owned	1033	86	$	14.63
	751	135	LPS	Yard Lights - Owned	730	61	$	9.85
	752	90	LPS	Yard Lights - Owned	521	43	$	6.91
	753	250	Flood	Yard Lights - Rented	1283	107	$	35.92
	754	400	Flood	Yard Lights - Rented	1886	157	$	44.73
	755	250	Halide	Yard Lights - Rented	1148	95	$	37.84
	756	400	Halide	Yard Lights - Rented	1878	156	$	46.57
	757	1000	Halide	Yard Lights - Rented	4346	362	$	79.93
	758	70	Halide	St Lights - Owned	390	32	$	5.40
	759	100	Halide	St Lights - Owned	533	44	$	7.39
	760	175	Halide	St Lights - Owned	894	74	$	12.40
	761	250	Halide	St Lights - Owned	1148	95	$	15.91
	762	400	Halide	St Lights - Owned	1878	156	$	26.01
	763	1000	Halide	St Lights - Owned	4346	362	$	60.20
	764	100	LED	St Lights - Owned	410	34	$	5.68
	765	150	Halide	St Lights - Owned	759	63	$	10.51
	766	72	LED	St Lights - Owned	295	25	$	4.08
	775	107	LED	St Lights - Owned	438	37	$	6.07
	780	143	LED	St Lights - Owned	586	49	$	8.12
	785	175	LED	St Lights - Owned	718	60	$	9.93

* These changes are applicable to existing fixtures only

Schedule of "Adjusted Rates"

Maritime Electric Company Limited

Applied to Bills Effective March 1, 2016

			Rates
610	Energy Charge per kWh for first 2,000 kWh		$ 4.38
611	Pole Rental -Concrete		$ 7.96
	Unmetered Rates (based on 100 watt fixture)		
810	8 Hour Lighting per kWh		$ 0.1661
	Energy Charge per kWh for first 2,000 kWh		$ 11.67
820	12 Hour Lighting per kWh		$ 0.1661
	Energy Charge per kWh for first 2,000 kWh		$ 11.67
830	24 Hour Lighting per kWh		$ 0.1661
	Energy Charge per kWh for first 2,000 kWh		$ 11.67
840	Energy Charge per kWh for first 2,000 kWh	Currently no customers in this rate category	
850	Outdoor Christmas Lighting: 5.77¢ per watt of connected load per week		
234	Customer Owned Outdoor Recreational Lighting		
	Service Charge		$ 24.57
	Energy Charge per kWh for first 2,000 kWh		$ 0.1661
	Energy Charge per kWh for balance of kWh		$ 0.1020
	Short Term Unmetered Rates	Currently no customers in this rate category	
	Energy Charge:		
	per kWh of estimated consumption		$ 0.1661

	Single-Phase	Three-Phase
Connection Charge:		
A. Connecting to existing secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17

APPENDIX D

Revised Financial Statements

APPENDIX D
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Earnings

	Actual 2015	Forecast 2016	Forecast 2017	Forecast 2018
Revenue				
Revenue Requirement	$ 185,227,031	$ 188,687,300	$ 201,518,900	$ 210,620,700
Operating Expenses (net of ECAM)	137,818,798	136,249,800	147,181,200	154,201,300
Amortization - Fixed Assets	15,886,668	21,045,600	21,981,400	22,983,800
Amortization - Deferred Charges	207,362	93,400	415,900	666,400
Operating Income	31,314,203	31,298,500	31,940,400	32,769,200
Financing Costs	12,277,307	12,388,000	12,433,300	12,644,900
Earnings Before Income Taxes	19,036,896	18,910,500	19,507,100	20,124,300
Income Taxes	6,001,467	5,976,200	6,160,100	6,350,300
Net Earnings - Regulated	$ 13,035,429	$ 12,934,300	$ 13,347,000	$ 13,774,000
Fortis Inc Head Office Costs (net of tax) [1]	334,650	463,000	483,700	505,800
Net Earnings - Non-Regulated	$ 12,700,779	$ 12,471,300	$ 12,863,300	$ 13,268,200
Return on Average Common Equity (%) - Non-Regulated	9.41%	9.02%	9.01%	9.01%
Return on Average Common Equity (%) - Regulated	9.75%	9.35%	9.35%	9.35%

1 Costs disallowed in calculating the Annual Revenue Requirement and Regulated Return as per Order UE09-02

APPENDIX D
Maritime Electric
Financial Results (Actual and Forecast)
Balance Sheets

	Actual 2015	Forecast 2016	Forecast 2017	Forecast 2018
ASSETS				
Fixed Assets				
Property, plant and equipment	$ 573,109,433	$ 599,638,800	$ 627,337,700	$ 656,502,600
Less: Accumulated amortization	194,466,955	210,643,300	229,754,500	249,879,300
	378,642,478	388,995,500	397,583,200	406,623,300
Other Long-Term Assets				
Costs Recoverable from Customers (Post-2003)	2,467,325	1,453,000	716,800	278,900
Intangible assets	4,105,909	4,650,000	4,750,000	4,800,000
Deferred charges	1,868,817	3,431,300	5,213,800	6,826,800
	8,442,051	9,534,300	10,680,600	11,905,700
Current Assets				
Accounts receivable	37,177,300	47,032,200	48,742,500	47,979,900
Materials and supplies	5,163,885	5,700,000	5,800,000	5,850,000
Prepaid expenses	494,895	488,600	474,900	455,300
	42,836,080	53,220,800	55,017,400	54,285,200
TOTAL ASSETS	$ 429,920,609	$ 451,750,600	$ 463,281,200	$472,814,200
SHAREHOLDER'S EQUITY AND LIABILITIES				
Shareholder's Equity				
Common shares	$ 31,100,681	$ 31,100,700	$ 31,100,700	$ 31,100,700
Retained earnings	104,998,735	110,267,500	115,114,500	120,388,400
	136,099,416	141,368,200	146,215,200	151,489,100
Long-term Debt	166,577,325	194,383,600	194,397,300	179,416,900
Other Long-Term Liabilities				
Future income taxes	26,781,364	22,000,000	21,000,000	17,500,000
Contributions	25,439,503	24,720,700	23,990,900	23,250,000
	52,220,867	46,720,700	44,990,900	40,750,000
Current Liabilities				
Bank indebtedness	4,548,000	-	-	-
Short-term borrowings	17,500,000	15,588,500	21,765,700	43,324,100
Rebates Payable to Customers	18,473,243	14,611,800	9,261,000	4,950,100
Future income taxes	-	6,954,600	10,302,400	16,330,500
Regulatory Liability (Asset) - OPEB	5,013,477	3,319,500	1,694,700	69,900
Accounts payable and accrued liabilities	29,488,281	28,803,700	34,654,000	36,483,600
	75,023,001	69,278,100	77,677,800	101,158,200
TOTAL SHAREHOLDER'S EQUITY AND LIABILITIES	$ 429,920,609	$ 451,750,600	$ 463,281,200	$472,814,200
Capital Structure - Year End				
Total Debt	58.1%	60.0%	60.0%	60.0%
Common Equity	41.9%	40.0%	40.0%	40.0%
	100.0%	100.0%	100.0%	100.0%

APPENDIX D
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Cash Flows

	Actual 2015	Forecast 2016	Forecast 2017	Forecast 2018
Cash Flow from Operating Activities				
Net Earnings	$ 13,035,429	$ 12,934,300	$ 13,347,000	$ 13,774,000
Add (deduct) non-cash items:				
Amortization - Fixed Assets	15,890,030	21,045,600	21,981,400	22,983,800
Amortization - Deferred Charges	209,321	99,700	429,600	686,000
Future income taxes	(3,417,746)	2,173,300	2,347,800	2,528,100
Changes in non-cash working capital	(3,691,057)	(14,978,150)	(1,888,200)	(2,638,600)
	22,025,977	21,274,750	36,217,600	37,333,300
Cash Flow From Financing Activities				
Issuance (Repayment) of long-term debt	-	28,000,000	-	(15,000,000)
Contributions	382,693	400,000	400,000	400,000
Financing Fees	-	(200,000)	-	-
Payment of dividends - Regulated	(8,000,000)	(8,000,000)	(8,500,000)	(8,500,000)
- Non-regulated	(3,184,271)	(297,500)	(297,500)	(297,500)
	(10,801,578)	19,902,500	(8,397,500)	(23,397,500)
Cash Flow from Investing Activities				
Expenditures for Fixed Assets (Net)	(30,602,399)	(33,061,850)	(31,798,900)	(33,214,800)
Deferred Charges	1,888	(1,655,900)	(2,198,400)	(2,279,400)
	(30,600,511)	(34,717,750)	(33,997,300)	(35,494,200)
Increase (Decrease) in Cash	(19,376,112)	6,459,500	(6,177,200)	(21,558,400)
Bank Indebtedness, Beginning of Year	(2,671,888)	(22,048,000)	(15,588,500)	(21,765,700)
Bank Indebtedness, End of Year	($22,048,000)	($15,588,500)	($21,765,700)	($43,324,100)

APPENDIX E

Revised Monthly ECAM Calculations
January 1, 2016 to December 31, 2018

APPENDIX E
Forecast Monthly ECAM Calculation - January 1, 2016 to December 31, 2018

Energy Cost Adjustment Mechanism	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Purchased Energy Costs	5,171,204	5,406,169	5,168,365	5,546,931	6,243,548	4,466,745	4,702,065	5,050,330	3,905,238	4,235,964	4,780,958	5,593,812	60,271,331
Lepreau Energy Costs	1,591,928	1,626,159	1,684,776	1,384,210	1,435,776	1,744,284	1,722,550	1,754,015	1,733,936	1,714,843	1,728,739	1,734,873	19,856,089
Generation Fuel Costs-PEI Plants	833,053	252,521	252,521	33,431	33,431	6,000	225,091	225,091	6,000	34,088	89,518	516,176	2,506,920
PEI Plant Operating Costs	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	4,872,808
Less: Insurance, Property Tax & Training	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(890,892)
Amortization - Pt Lepreau Deferred Charge & DSM	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	93,400
Renewable Energy Costs	2,585,564	1,937,302	2,171,011	2,380,818	1,263,116	1,485,798	1,836,994	1,379,115	2,144,631	2,171,522	2,399,316	2,353,671	24,108,858
	10,521,359	9,561,761	9,616,283	9,685,000	9,315,480	8,042,437	8,826,309	8,748,161	8,129,414	8,496,027	9,338,141	10,538,142	110,818,514
Net Purchased & Produced Energy - kWh (NPP)	123,659,525	114,662,632	115,051,628	101,382,791	99,057,818	95,175,865	104,365,755	103,314,768	95,919,856	101,396,791	111,104,675	122,753,536	1,287,845,638
Base Rate/kWh	0.08760	0.08760	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08634
Base Energy Costs	10,832,574	10,044,447	9,900,193	8,723,989	8,523,925	8,189,883	8,980,673	8,890,236	8,253,904	8,725,194	9,560,557	10,562,942	111,188,517
Difference Between Actual & Base Energy Costs	(311,216)	(482,686)	(283,909)	961,011	791,555	(147,446)	(154,364)	(142,075)	(124,489)	(229,167)	(222,416)	(24,799)	(370,003)
Opening Balance - ECAM	2,467,324	2,837,123	3,020,397	2,528,524	3,288,615	3,886,271	3,549,593	3,206,212	2,855,863	2,535,318	2,122,389	1,698,847	2,467,324
Additions/(Reductions)	(311,216)	(482,686)	(283,909)	961,011	791,555	(147,446)	(154,364)	(142,075)	(124,489)	(229,167)	(222,416)	(24,799)	(370,003)
Rebated/(Collected) From Ratepayer	681,015	665,959	(207,964)	(200,919)	(193,899)	(189,231)	(189,017)	(208,274)	(196,055)	(183,762)	(201,125)	(221,081)	(644,354)
Closing Balance - ECAM	2,837,123	3,020,397	2,528,524	3,288,615	3,886,271	3,549,593	3,206,212	2,855,863	2,535,318	2,122,389	1,698,847	1,452,967	1,452,967
Cost to Residential Customer (650 kWh/Month)	$ (3.87)	$ (3.87)	$ 1.34	$ 1.34	$ 1.34	$ 1.34	$ 1.34	$ 1.34	$ 1.34	$ 1.34	$ 1.34	$ 1.34	$ 5.64

Energy Cost Adjustment Mechanism	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Purchased Energy Costs	5,493,270	5,685,014	5,732,452	4,709,423	5,516,166	5,170,412	5,412,543	5,790,106	4,597,295	5,069,133	5,534,160	6,639,833	65,349,806
Lepreau Energy Costs	1,730,514	1,686,478	1,745,418	1,648,041	1,701,339	1,696,058	1,686,163	1,720,876	1,681,962	1,706,465	1,703,412	1,692,264	20,398,989
Generation Fuel Costs-PEI Plants	1,452,900	360,991	360,991	53,550	53,550	6,000	313,441	313,441	6,000	56,317	219,875	481,017	3,678,071
PEI Plant Operating Costs	415,555	415,555	415,555	415,555	415,555	415,555	415,555	415,555	415,555	415,555	415,555	415,555	4,986,664
Less: Insurance, Property Tax & Training	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(76,468)	(917,619)
Amortization - Pt Lepreau Deferred Charge & DSM	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656	415,876
Renewable Energy Costs	2,601,729	1,893,159	2,217,029	2,362,739	1,307,745	1,459,951	1,891,768	1,406,195	2,144,397	2,136,385	2,399,916	2,403,099	24,224,113
	11,652,157	9,999,385	10,429,633	9,147,496	8,952,543	8,706,164	9,677,658	9,604,361	8,803,398	9,342,045	10,231,107	11,589,955	118,135,900
Net Purchased & Produced Energy - kWh (NPP)	125,800,160	113,538,534	116,909,431	103,466,842	101,590,899	98,078,006	106,761,741	105,753,772	97,839,014	104,588,808	114,026,519	126,067,152	1,314,420,879
Base Rate/kWh	0.08605	0.08605	0.08988	0.08988	0.08988	0.08988	0.08988	0.08988	0.08988	0.08988	0.08988	0.08988	0.08918
Base Energy Costs	10,825,104	9,769,991	10,507,820	9,299,600	9,130,990	8,815,251	9,595,745	9,505,149	8,793,771	9,400,442	10,248,704	11,330,916	117,223,481
Difference Between Actual & Base Energy Costs	827,053	229,394	(78,186)	(152,104)	(178,447)	(109,088)	81,913	99,212	9,627	(58,398)	(17,597)	259,040	912,419
Opening Balance - ECAM	1,452,967	2,039,377	2,033,417	1,832,736	1,562,303	1,269,698	1,049,222	1,019,920	996,552	890,766	724,158	588,010	1,452,967
Additions/(Reductions)	827,053	229,394	(78,186)	(152,104)	(178,447)	(109,088)	81,913	99,212	9,627	(58,398)	(17,597)	259,040	912,419
Rebated/(Collected) From Ratepayer	(240,643)	(235,354)	(122,495)	(118,329)	(114,158)	(111,388)	(111,215)	(122,580)	(115,413)	(108,211)	(118,551)	(130,299)	(1,648,634)
Closing Balance - ECAM	2,039,377	2,033,417	1,832,736	1,562,303	1,269,698	1,049,222	1,019,920	996,552	890,766	724,158	588,010	716,751	716,751
Cost to Residential Customer (650 kWh/Month)	$ 1.34	$ 1.34	$ 0.77	$ 0.77	$ 0.77	$ 0.77	$ 0.77	$ 0.77	$ 0.77	$ 0.77	$ 0.77	$ 0.77	$ 10.40

APPENDIX E

Forecast Monthly ECAM Calculation - January 1, 2016 to December 31, 2018

Energy Cost Adjustment Mechanism	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Total**
Purchased Energy Costs	6,645,708	6,128,747	5,865,040	6,363,036	7,023,544	5,317,013	5,527,912	5,838,613	4,596,989	5,175,644	5,713,588	6,691,365	70,887,200
Lepreau Energy Costs	1,724,037	1,660,404	1,704,703	1,578,482	1,615,365	1,712,741	1,714,933	1,713,169	1,707,446	1,709,738	1,704,080	1,708,817	20,253,914
Generation Fuel Costs-PEI Plants	464,045	342,198	342,198	30,090	30,090	6,000	318,107	318,107	6,000	30,090	30,090	464,045	2,381,061
PEI Plant Operating Costs	424,993	424,993	424,993	424,993	424,993	424,993	424,993	424,993	424,993	424,993	424,993	424,993	5,099,920
Less: Insurance, Property Tax & Training	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(78,762)	(945,148)
Amortization - Pt Lepreau Deferred Charge & DSM	55,535	55,535	55,535	55,535	55,535	55,535	55,535	55,535	55,535	55,535	55,535	55,535	666,416
Renewable Energy Costs	2,625,349	1,910,605	2,237,576	2,385,205	1,319,912	1,471,585	1,912,302	1,422,546	2,164,639	2,159,312	2,422,221	2,424,916	24,456,168
	11,860,905	10,443,720	10,551,282	10,758,578	10,390,678	8,909,104	9,875,021	9,694,201	8,876,840	9,476,549	10,271,744	11,690,909	122,799,532
Net Purchased & Produced Energy - kWh (NPP)	128,499,511	115,833,756	118,439,706	105,521,956	103,232,000	99,848,066	109,553,878	107,601,916	99,238,078	107,312,921	117,037,733	128,358,514	1,340,478,035
Base Rate/kWh	0.08988	0.08988	0.09161	0.09161	0.09161	0.09161	0.09161	0.09161	0.09161	0.09161	0.09161	0.09161	0.09129
Base Energy Costs	11,549,536	10,411,138	10,850,261	9,666,866	9,457,084	9,147,081	10,036,231	9,857,412	9,091,200	9,830,937	10,721,827	11,758,923	122,378,496
Difference Between Actual & Base Energy Costs	311,368	32,582	(298,979)	1,091,712	933,594	(237,977)	(161,210)	(163,210)	(214,360)	(354,387)	(450,083)	(68,014)	421,035
Opening Balance - ECAM	716,751	886,373	780,371	420,939	1,454,263	2,331,544	2,038,631	1,822,593	1,598,935	1,327,650	919,883	411,263	716,751
Additions/(Reductions)	311,368	32,582	(298,979)	1,091,712	933,594	(237,977)	(161,210)	(163,210)	(214,360)	(354,387)	(450,083)	(68,014)	421,035
Rebated/(Collected) From Ratepayer	(141,747)	(138,584)	(60,452)	(58,388)	(56,313)	(54,936)	(54,829)	(60,447)	(56,925)	(53,380)	(58,536)	(64,332)	(858,869)
Closing Balance - ECAM	886,373	780,371	420,939	1,454,263	2,331,544	2,038,631	1,822,593	1,598,935	1,327,650	919,883	411,263	278,918	278,918
Cost to Residential Customer (for 650 kWh)	$ 0.77	$ 0.77	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 5.28