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 April 1, 2009 and for certain approvals incidental to such an order.

APPLICATON
and
EVIDENCE OF
MARITIME ELECTRIC COMPANY, LIMITED

Date: October 2, 2008

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd)

APPENDICES

1.0 APPLICATION

C A N A D A

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Introduction

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

Application

2. Maritime Electric hereby applies for an order of the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") approving the rates, tolls and charges ("rates") for electric service, which are outlined in Appendix 1, for the period beginning April 1, 2009. The General Rules and Regulations are not included as they are the subject of a separate Application. Maritime Electric proposes adjustments to the base rate per kWh contained in the Energy Cost Adjustment Mechanism calculation to reflect increases in energy related costs. The Company is also requesting a Return on Average Common Equity order from the Commission in respect of the 2009 fiscal year.

3. The proposals contained in this Application represent a just and reasonable balance of the interests of Maritime Electric and those of its customers and will, if approved, allow the Company to continue to provide a high level of service at prices that are, in all circumstances, reasonable.

Procedure

4. Filed herewith is the Affidavit of Frederick J. O'Brien, J. William Geldert, John D. Gaudet and Steven D. Loggie which contains the evidence on which Maritime Electric relies in this Application.

Dated at Charlottetown, Province of Prince Edward Island, this 2nd day of October 2008.

D. Spencer Campbell,

Thomas P. Laughlin

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2.0 AFFIDAVIT

C A N A D A

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AFFIDAVIT

We, Frederick James O'Brien, of Alberton, in Prince County, and John William Geldert, John David Gaudet and Steven David Loggie 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 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 Electric Power Act 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 known as Exhibit "A", contained at Tabs 3 through 15 inclusive.

4. The evidence found at Tab 3 (the "Introduction") contains a brief overview of Maritime Electric.

5. The evidence found at Tab 4 (the "Capital Structure") contains information with respect to the impact of the increased energy costs on the Company's capital structure.

6. The evidence found at Tab 5 (the "Energy Cost Adjustment Mechanism" or "ECAM") contains background information on the history and operation of the Energy Cost Adjustment Mechanism.

7. The evidence found at Tab 6 (the "Proposed Rebasing of ECAM") contains the Company's proposal with respect to the rebasing.

8. The evidence found at Tab 7 (the "Energy Sales Forecast") outlines the Company's energy sales forecast.

9. The evidence found at Tab 8 (the "General and Administrative Expenses") details the administrative and overhead costs, not directly related to energy sales, required to operate the Company.

10. The evidence found at Tab 9 (the "Transmission and Distribution Expenses") outlines the cost to deliver the forecast energy (the "wires" cost) to customers.

11. The evidence found at Tab 10 (the "Energy Supply Expenses") contains a summary of the energy, by source, required to meet the forecast energy sales.

12. The evidence contained at Tab 11 (the "Costs Recoverable From Customers") outlines the Company's proposal to continue to amortize Costs Recoverable From Customers that it would have been able to recover under the Maritime Electric

Company Regulation Act and the Base Rate Adjustment Regulations as per Section 47(4)(a)(i) of the EPA.

13. The evidence found at Tab 12 (the "Financial Objectives") contains an outline of the Company's financial objectives.

14. The evidence found at Tab 13 (the "Financial Forecast") contains the forecast financial results based on the evidence contained in the Application.

15. The evidence found at Tab 14 (the "Impact on Customers' Costs") illustrates the impact of the Company's Application on a Rural Residential Customer's annual costs.

16. Tab 15 contains a proposed Order of the Commission based on the Company's Application.

SWORN TO SEVERALLY at
Charlottetown, Prince Edward
Island, the 30th day of September, 2008,
Before me:

Frederick J. O'Brien

J. William Geldert

John D. Gaudet

Steven D. Loggie

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

3.0 INTRODUCTION

3.1 Corporate Profile

Maritime Electric Company, Limited, a wholly-owned subsidiary of Fortis Properties Corporation (a wholly-owned subsidiary of Fortis Inc.) owns and operates a fully integrated system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island. The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton. The Company has contractual entitlement to capacity and energy from NB Power's Dalhousie and Point Lepreau Generating Stations and an agreement for the purchase of system energy from NB Power delivered via two submarine cables leased from the Province of Prince Edward Island. The Company also purchases wind powered energy from on-Island sources.

3.2 Overview of Evidence

This evidence is filed in support of the Company's Application for rates, tolls and charges for service to its customers on Prince Edward Island for the period beginning April 1, 2009. The Application is filed pursuant to Section 20 of the EPA.

4.0 CAPITAL STRUCTURE

4.1 Background

The Electric Power Act states "Maritime Electric Company, Limited shall, at all times, maintain not less than 40% of the capital it has invested in the power system, determined in accordance with generally accepted accounting principles, in the form of common equity".

The common equity percentage in the Company's capital structure has been decreasing steadily since 2004. The continued increase in the percentage of debt in the capital structure is a result of the increase in energy related costs and the operation of the Energy Cost Adjustment Mechanism ("ECAM"). As unit costs for energy exceeded the $0.0673/kWh base rate, an increasing amount of the energy costs have been placed on the Company's Balance Sheet for future recovery from customers. This means that the Company has had to increase its short-term borrowing to pay its operating costs and finance investment in the energy delivery system since the balance being deferred (on a monthly basis) for future recovery under the ECAM is larger than the amount being recovered from customers on a monthly basis.

As shown in Schedule 1, during the period November 2006 to August 2008, Maritime Electric deferred $40,899,114 in purchased/produced energy costs for future recovery. These energy costs, which will ultimately be recovered from customers, must, in the interim, be financed through short-term borrowing. With the forecast continuation of increased energy costs and without a rebasing of the ECAM, this difference is expected to continue, resulting in an extremely large recoverable on the Company's Balance Sheet. This will negatively affect the Company's ability to borrow the funds necessary to finance its capital programs.

SCHEDULE 1 Analysis of Energy Costs Deferred for Recovery Versus Amount Collected (November 2006 – August 2008) ($)			
Month	**Energy Costs Deferred**	**Energy Costs (Rebated) Collected**	**Difference**
November 2006	1,521,307	(380,764)	1,902,071
December 2006	1,905,176	(409,756)	2,314,932
January 2007	2,692,163	- *	2,692,163
February 2007	2,462,733	- *	2,462,733
March 2007	1,852,402	- *	1,852,402
April 2007	2,764,227	401,223	2,363,004
May 2007	594,210	369,206	225,004
June 2007	700,455	478,047	222,408
July 2007	1,661,658	435,393	1,226,265
August 2007	1,526,098	439,246	1,086,852
September 2007	823,480	757,525	65,955
October 2007	2,196,298	721,005	1,475,293
November 2007	3,166,792	687,597	2,479,195
December 2007	2,618,234	863,386	1,754,848
January 2008	3,063,662	1,382,250	1,681,412
February 2008	2,914,189	1,119,717	1,794,472
March 2008	3,798,000	1,358,375	2,439,625
April 2008	3,255,233	1,383,189	1,872,044
May 2008	3,868,115	2,549,310	1,318,805
June 2008	5,167,775	2,827,243	2,340,432
July 2008	6,680,947	3,119,425	3,561,522
August 2008	7,359,995	3,592,318	3,767,677
Total	**62,593,149**	**21,694,035**	**40,899,114**

* Order UE06-07 set the ECAM rate at nil for these months.

A compounding factor, beginning on April 1, 2008, is the refurbishment of the Point Lepreau Nuclear Generating Station[1]. Maritime Electric has an entitlement to 4.72% of all the energy produced by the Station. In return the Company must pay 4.72% of all operating and capital related costs. The Station has been out of service since April 1, 2008 and is not scheduled to return to service until September 30, 2009. During that time the Company will continue to pay its share of the operating and capital costs. There will, however, be no energy produced by the Station during that period and Maritime Electric must procure replacement energy to meet customers' needs. This replacement energy comes at an extra cost, expected to be approximately $28.0 million during the refurbishment period.

[1] The unit is being refurbished to extend the operating life by 25 years. Maritime Electric's share of the refurbishment costs will be paid over the extended life of the unit.

This places further pressure on the capital structure, as the Company has to increase its short-term borrowing to finance its operating and capital costs.

The Company proposes that beginning in January 2009 the monthly cost to procure this replacement energy be excluded from the monthly ECAM rate calculation (for the period January 1, 2009 to September 30, 2009) and that this amount (approximately $14.0 million) be amortized back into the ECAM rate calculation over a 10 year period beginning in October 2009. This will enable the Company to begin to phase in its rebasing proposal as contained in Section 6.0. The extended amortization concept proposed here is not new for Maritime Electric. The settlement reached between Maritime Electric and NB Power in 2000 in respect of the $450,000,000 write-down of the Point Lepreau Nuclear Generating Station is being amortized over the life of the unit. The purpose of the extended amortization period is to reduce the impact on customers and to ensure that the Company is able to maintain the common equity component of its capital structure above the 40 per cent requirement of the EPA. If the 2009 replacement energy costs were not deferred the impact on customers in 2009 would be a further increase of 3.0 percent.

4.2 Summary

A summary of this section follows:

- Management proposes that the 2009 monthly cost to procure replacement energy during the Point Lepreau refurbishment be excluded from the monthly ECAM rate calculation for the period January 1, 2009 to September 30, 2009 and that this amount be amortized back into the ECAM rate calculation over a 10 year period beginning in October 2009.

5.0 ENERGY COST ADJUSTMENT MECHANISM

5.1 Background

The amount charged to customers for electrical service contains two components. The first component is the Basic Rate which recovers the revenue requirement, including a base amount for energy related costs. The second component is the Energy Cost Adjustment Mechanism, which enables the utility to collect/return approved energy related costs above/below the base amount per kilowatt-hour ("kWh") included in the Basic Rates. In a period of volatile energy costs (such as currently being experienced) the operation of the ECAM provides a smoothing effect to the collection or rebate of these costs. Mechanisms such as the ECAM exist in various forms and are used by utilities across North America. Most recently, Nova Scotia Power received approval for a Fuel Adjustment Mechanism to help recover increased energy related costs.

Maritime Electric has had a mechanism to recover/rebate energy costs above/below a base amount in place since the 1970's[2]. The mechanism has undergone several changes during that period, however, the fundamental objective has remained the same. Throughout the period the mechanism has enabled the Company to collect/return approved energy related costs above/below a pre-determined base rate per kWh.

The current ECAM was approved by the Commission on January 6, 2005 through Order UE05-01 and had application to the period beginning on January 1, 2004. On March 16, 2005 the Commission issued Order UE05-05 confirming the operation of the ECAM. In Order UE05-06 the Commission ruled that the ECAM remain in effect until June 30, 2006 and be replaced with an ECAM that reflected a reduced number of accounts, yet to be determined, that would be subject to the ECAM adjustment. On January 24, 2008 the Commission issued Order UE08-01 requiring the Company to file a report with the Commission by September 1, 2008 providing recommendations for rebasing the ECAM. The date was subsequently changed to October 15, 2008. On April 10, 2008 the

[2] During the period 1994 – 2000 there was no mechanism in place.

Commission issued Order UE08-06 changing the amortization period contained in the ECAM from 12 months to 8 months beginning in May 2008[3].

5.2 Operation of the ECAM

The ECAM currently reflects a base rate for energy of $0.0673/kWh in the calculation. This represents the budgeted composite cost per kWh, contained in Basic Rates, for purchased and produced energy in 2004, the year to which the current ECAM was first applied. Since that time the cost to purchase/produce energy has increased substantially due to various market influences while the amount recovered through Basic Rates has not changed. The effect of the operation of the ECAM is a smoothing of the costs charged to customers for purchased/produced energy. This smoothing removes the effect of sharp increases/decreases in energy prices, resulting in more gradual increases/decreases to customers.

Under the operation of the ECAM the Company charges to expense, on a monthly basis, an amount equal to the net purchased and produced energy for the month ("NPP") multiplied by $0.0673/kWh. This amount is subtracted from the actual cost of energy purchased or produced during the month with the difference placed on the Balance Sheet for future recovery from or return to customers. The details of the operation of the ECAM were provided in IRAC Order UE05-05.

The following Schedule shows the actual composite cost per kWh to purchase and produce the energy required to meet customer requirements during the period 2004 – 2007.

SCHEDULE 2				
Cost of Purchased and Produced Energy per kWh (2004 – 2007) ($)				
	2004	**2005**	**2006**	**2007**
Cost of Purchased and Produced Energy per kWh	0.0705	0.0620	0.0644	0.0879

[3] It is assumed that the amortization period returns to 12 months during 2009.

Schedule 3 shows the balance of Costs Recoverable From (Payable To) Customers at December 31 for the years 2004 – 2007. Note that at December 31, 2005 and 2006 there was actually an amount payable to customers under the operation of the ECAM reflecting the energy pricing available at the time.

SCHEDULE 3				
Costs Recoverable From (Payable To) Customers (2004 – 2007) ($)				
	2004	**2005**	**2006**	**2007**
Costs Recoverable From (Payable To) Customers	2,725,389	(3,343,489)	(2,991,006)	14,915,116

The substantial increase in 2007 reflects the Energy Purchase Agreement that covered the period November 1, 2006 to March 31, 2008. This agreement, with NB Power, completed the transition from cost based pricing to pricing based on the New England Market. Generally speaking the prices received by NB Power for the sale of energy into the New England Market determine the prices paid by Maritime Electric for system energy purchases from NB Power.

The significant increase in energy costs, in such a short period of time, has resulted in Maritime Electric making significant expenditures to purchase the energy required to serve its customers while the collection of these costs is delayed by the operation of the ECAM. The Company's short-term operating loan increased from $51.3 million at December 31, 2006 to $67.0 million at December 31, 2007 as a result of these increased expenditures. This is further evidenced in the balance of Costs Recoverable From Customers which increased by $17.9 million at December 31, 2007 over December 31, 2006.

5.3 Summary

A summary of this section follows:

- An ECAM has been in place since the early 1970's and has been effective in providing for the recovery/return of energy related costs above/below a pre-determined base. The significant increase in energy related costs has necessitated a change (rebasing) of the ECAM base rate to collect these higher costs on a more timely basis.
- Contained within this Application is Maritime Electric's proposal to rebase the ECAM as per IRAC Order UE08-01.

6.0 PROPOSED REBASING OF ECAM

6.1 Background

Order UE08-01 required the Company to file a report with the Commission in 2008 containing a recommendation for rebasing the ECAM.

6.2 Outline

As outlined earlier, Maritime Electric has seen significant increases in the cost of the energy it purchases/produces to meet the requirements of its customers. These increases are driven by a number of factors including the transition to New England Market based pricing by NB Power, increases in the price of fossil fuel used to generate this electricity, and the cost to procure replacement energy during the refurbishment of the Point Lepreau Nuclear Generating Station. These increased costs are being recovered through the operation of the ECAM but the delay in recovery is having significant negative implications for Maritime Electric. The balance of recoverable costs on Maritime Electric's Balance Sheet could exceed $60 million by 2012 if action is not taken to rebase the ECAM and permit these costs to be collected sooner. Such an accumulation, and the associated cash flow constraints, could have a negative impact on the Company's credit rating and its ability to borrow short-term or long-term funds, preventing the Company from financing the necessary capital expenditures to ensure system reliability. At the very least, such an erosion in the Company's credit quality will result in significantly higher borrowing costs.

Maritime Electric proposes to increase the base rate per kWh in the ECAM calculation to facilitate an increase in the recovery of approved energy related costs through Basic Rates rather than through the operation of the ECAM. This will represent an increase in the amount of energy related costs collected from customers under the Basic Rate component of the monthly bill. The ECAM will remain in place but the amount of cost recovery through this mechanism will be reduced as the base rate per kWh in the mechanism is increased.

The targeted base rate per kWh proposed by Maritime Electric is $0.1100/kWh which reflects the current forecast of the unit cost per kWh for energy in 2011.

This forecast assumes a $0.95 Canadian dollar and 2009 oil prices in the range of $104 to $110 per barrel. Changes to these inputs will result in changes in the forecast/actual cost of purchased/produced energy throughout the forecast period. The following Schedule illustrates the impact to a Rural Residential Customer using 650 kWh/month of changes in oil prices and the value of the Canadian dollar for 2009.

SCHEDULE 4			
2009 Oil Price and Foreign Exchange Rate Changes			
Item	**Change**	**Annual Effect on Maritime Electric Energy Costs**	**Annual Effect on Rural Residential Customer**
Oil	± $5/barrel	± $5,700,000	± $14.22/± 0.9%
Exchange	± 5 cents	± $4,100,000	± $10.24/± 0.7%

It is not the Company's intention to move to the proposed base rate per kWh immediately as it must balance its needs with the costs charged to customers. Maritime Electric proposes that the rebasing be phased in over four years with the first adjustment to take place on April 1, 2009. The following Schedule shows the proposed base rate per kWh to be used in the ECAM calculations for the period 2008 – 2012, with each change proposed to take place on April 1 of each year shown. It is important to note that the proposed adjustments for 2011 and 2012 are based on current forecasts for energy costs and are subject to change based on the proposed filing dated November 15, 2010 in Section 6.4.

SCHEDULE 5					
Proposed ECAM Base Rate Per kWh (2008 – 2012) ($)					
	April 1, 2008	**April 1, 2009**	**April 1, 2010**	**April 1, 2011**	**April 1, 2012**
Proposed ECAM Base Rate per kWh	0.0673	0.0770	0.0900	0.1000	0.1100

With the proposed rebasing (an increase in the amount of the basic unit cost in the ECAM calculation) there is a reduction in the amount collected through ECAM but a corresponding increase in the amount collected through Basic Rates. In order to facilitate the proposed changes in the base rate per kWh used in the ECAM calculation for the period 2008 – 2012, adjustments to Basic Rates

are required. It is important to note that these adjustments reflect rebasing only and do not address potential increases in revenue requirement resulting from non-energy related costs. The following Schedule shows the adjustment to Basic Rates as a result of the rebasing proposal. The actual annual increases that customers can expect to see will reflect the continued operation of the ECAM as well as the adjustments to Basic Rates.

SCHEDULE 6				
Adjustment to Basic Rates Due to Rebasing (2009 – 2012) (%)				
	April 1, 2009	April 1, 2010	April 1, 2011	April 1, 2012
Adjustment to Basic Rates due to Rebasing	8.40	9.80	6.90	7.40

The overall annual impact of the Application on a rural residential customer using 650 kWh per month can be found in Schedule 31 in Section 14 of the Application.

6.3 Costs Recoverable From Customers

With the proposed increase in the base rate per kWh in the ECAM calculation comes a reduction in the amount to be deferred for future collection. The series of proposed changes, which would see the base rate per kWh increase from $0.0673 in 2008 to $0.1100 on April 1, 2012, will also see a reduction in the December 31 balance of Costs Recoverable From Customers during the period 2008 - 2012.

The forecast Costs Recoverable From Customers for the period 2008 - 2012, with and without the proposed rebasing are shown below:

SCHEDULE 7					
Forecast Costs Recoverable From Customers (2008 – 2012) ($)					
	2008	2009	2010	2011	2012
Without Rebasing	32,514,839	54,095,861	56,468,642	58,712,125	60,200,337
With Rebasing	32,514,839	47,722,057	38,234,934	28,354,208	17,998,345

6.4 Capital Structure

The proposed rebasing will improve the Company's cash flow thereby reducing its borrowing requirements and associated financing costs. Schedule 8 shows the forecast capital structure for the period 2008 - 2012 if the proposed rebasing is approved.

SCHEDULE 8 Forecast Capital Structure (2008 – 2012) (%)					
	2008	**2009**	**2010**	**2011**	**2012**
Debt	58.4	57.8	58.5	58.5	58.4
Equity	41.6	42.2	41.5	41.5	41.6
Total	100.0	100.0	100.0	100.0	100.0

With the uncertainty over continued increases in the world price of fossil fuels and the changes due to an evolving industry, it is difficult to predict, with any certainty, where energy prices will be over the next four years. Management proposes that Maritime Electric be required, by November 15, 2010, to file an updated report with the Commission to determine if further changes to the base rate per kWh used in the ECAM calculation (increase or decrease) are required.

6.5 Summary

A summary of this section follows:

- Management proposes that the base rate to be used in the ECAM calculation for the period 2009 - 2012 be set as follows:

Proposed ECAM Base Rate per kWh (2009 – 2012) ($)				
	April 1, 2009	**April 1, 2010**	**April 1, 2011**	**April 1, 2012**
Proposed ECAM Base Rate per kWh	0.0770	0.0900	0.1000	0.1100

- Management proposes that Basic Rates be adjusted as follows to reflect the rebasing proposal. It is important to point out that although Basic Rates will increase, the monthly ECAM amount is expected to be decrease during the forecast period.

Proposed Increase in Basic Rates Due to Rebasing (2009 – 2012) (%)				
	April 1, 2009	**April 1, 2010**	**April 1, 2011**	**April 1, 2012**
Proposed Increase in Basic Rates	8.40	9.80	6.90	7.40

- Management proposes that the Company file an updated report on ECAM rebasing by November 15, 2010.

7.0 ENERGY SALES FORECAST

7.1 Economic Outlook[4]

Overall, real gross domestic product ("GDP") is forecast to grow by 1.9% over the forecast period. The goods-producing sector will get a boost from manufacturing with solid gains in aerospace, food-processing, and the engine, turbine, and power transmission equipment industries helping to stimulate manufacturing over the long-term. Over the long-term, Prince Edward Island is expected to benefit from positive net inter-provincial migration reinforcing the province's image as a retirement haven for Atlantic Canadians. However, the primary sectors of tourism, construction, agriculture and fishery are expected to weaken. GDP is forecast to grow at 1.4% annually over the next twenty years.

7.2 Energy Sales Forecast

The energy sales forecast is the basis of the planning process; in particular the short-term and long-term energy supply planning process. It is used to calculate the total energy required to service customers and the associated total energy related costs. The development of short-term energy sales forecasts begins with a two-year average growth rate calculation and an analysis of year-to-date growth over the previous period. These results are then compared to actual results and known economic inputs. The following Schedule outlines the results of that process.

SCHEDULE 9		
Forecast Energy Sales 2008 and 2009 (MWh)		
Measure	**2008 Forecast**	**2009 Forecast**
Two-year average growth	1,052,805	1,072,172
Year-to-date growth	1,035,127	1,036,661

The decrease in overall sales growth is due to the economic slowdown seen on PEI, the loss of a Large Industrial customer, reduced consumption in the agricultural sector compared to previous years and an increased focus on conservation by customers as electricity costs continue to rise. Growth rates for the Residential class are forecast to be 0.8 per cent in 2008 and 0.6 per cent for

[4] Conference Board of Canada – Summer Outlook 2008.

2009. General Service class growth rates are forecast to be 0.8 per cent for 2008 and 0.5 per cent for 2009. The forecast reflects the reduced growth seen in 2008 which is expected to continue into 2009.

Growth rates for the Large Industrial class are forecast to be 0.2 per cent in 2008 and 0.2 per cent in 2009. The loss of one customer in this class and reduced production by another will see growth muted. Growth in the Small Industrial class is forecast to decrease by 3.0 per cent in 2008 reflecting the transfer of a customer to the Large Industrial classification with modest growth of 0.1 per cent forecast for 2009. The growth rate for the Street Lighting/Unmetered class is forecast to be 3.8 per cent for 2008 and 2.3 per cent for 2009. Energy sales by class are shown in the following Schedule. Energy sales are forecast to be 1,039,017 MWh for 2008 and 1,044,215 MWh for 2009.

SCHEDULE 10
Energy Sales 2007 - 2009

	2007 Actual	2008 Forecast	2009 Forecast
Energy Sales (MWh)			
Residential	433,863	437,334	439,958
General Service I	365,269	367,460	369,298
General Service II	4,543	5,361	5,495
Large Industrial	149,652	150,013	150,357
Small Industrial	72,945	70,757	70,828
Street Lighting/Unmetered	7,794	8,092	8,279
Total Energy Sales	**1,034,066**	**1,039,017**	**1,044,215**
Growth Rate (%)			
Residential	5.0	0.8	0.6
General Service I	3.0	0.6	0.5
General Service II	(1.9)	18.0	2.5
Large Industrial	3.1	0.2	0.2
Small Industrial	(1.4)	(3.0)	0.1
Street Lighting/Unmetered	3.7	3.8	2.3
Overall Growth Rate	3.5	0.5	0.5

7.3 Demand Side Management

The Company's Demand Side Management ("DSM") Program was approved under Order UE08-02. Maritime Electric recognizes the need to provide leadership in helping customers understand how to use electricity wisely. Included in the DSM Program are programs designed to:

- Encourage the conversion to compact fluorescent lights ("CFLs");
- Introduce rebates and incentives to encourage the use of energy efficient holiday lighting and CFLs, and;
- Increase the education and awareness of the general public with respect to energy conservation opportunities.

7.4 Summary

A summary of this section follows:

- Energy sales are forecast to be 1,039,017 MWh for 2008 and 1,044,215 MWh for 2009.

8.0 GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses are comprised of internal and external costs required for the overall operation and management of the Company. Internal costs are comprised mainly of labour costs, while the external costs include such costs as communications costs, postage, insurance, property taxes, professional services and the cost of regulation.

8.1 General and Administrative Expenses

The following Schedule outlines the General and Administrative Expenses for the period 2007 - 2009.

SCHEDULE 11			
General and Administrative Expenses 2007 – 2009 ($)			
Description	**2007 Actual**	**2008 Forecast**	**2009 Forecast**
Supervision and Management	4,448,079	4,655,900	5,017,300
General Administration	976,535	1,097,500	1,184,800
Customer Service Support	752,685	798,300	834,700
Meter Reading	617,611	647,400	654,800
Insurance	745,324	650,000	608,300
Property Tax	1,617,829	1,670,000	1,745,100
Director's Fees	182,037	178,600	180,800
Professional Services	661,369	404,400	390,500
Regulation	404,852	425,000	522,700
General Property (net)	162,477	232,000	287,400
Total	**10,568,798**	**10,759,100**	**11,426,400**

Supervision and Management - $4,655,900 (2008), $5,017,300 (2009)

This category captures, amongst other things, the labour related costs for the Executive, Managerial and Supervisory staff. Costs associated with national, provincial and regional industry and business groups are also reflected here. Rating fees charged by Standard & Poor's, costs related to employee future benefits, travel costs, employee training costs, charitable contributions, corporate communications costs, and other general operating costs are charged here.

General Administration - $1,097,500 (2008), $1,184,800 (2009)

This account reflects the internal and external support costs associated with various corporate functions. The salaries of the administrative and clerical staff are included, along with office materials and supplies, courier charges,

communications, bill printing and enclosing, postage, and a provision for costs allocated by the Fortis Inc. head office, including various Securities Commission related costs.

Customer Service Support - $798,300 (2008), $834,700 (2009)

These costs reflect the operation of the Customer Service function. Included are salaries, costs paid to collection agents, damage claims, materials and supplies, bill payment processing costs, customer communications costs, bad debts expense and other miscellaneous costs.

Meter Reading - $647,400 (2008), $654,800 (2009)

This account reflects the cost of reading customers' meters for billing purposes. The costs include labour, materials, hand-held meter reading device maintenance costs and transportation costs. The Company continues a staged implementation of automated meter reading technology, to improve the accuracy of the process and improve the safety of employees. The efficiencies gained from this project will help manage costs in the future through reduced transportation charges and the redeployment of staff to other critical functions.

Insurance - $650,000 (2008), $608,300 (2009)

This account includes the cost of providing the necessary insurance coverage for the Company's activities, including property insurance, liability insurance, Directors and Officers insurance, and employee dishonesty insurance. Maritime Electric procures its insurance in conjunction with the Fortis group of companies to take advantage of bulk purchasing power.

Property Taxes - $1,670,000 (2008), $1,745,100 (2009)

Maritime Electric pays property taxes based on the following:

Tax on Physical Properties – This is a tax on the assessed values of its various physical properties (excluding distribution and transmission lines and generating equipment).

Revenue Related Tax – This tax is based upon a percentage (1.0 per cent) of the

Company's revenue and is a proxy for the taxation of the Company's distribution, transmission and generating assets as it is difficult to determine an accurate assessment of these assets.

Directors' Fees - $178,600 (2008), $180,800 (2009)

This account captures the fees paid to Maritime Electric's directors and expenses incurred by them while performing their duties as Board members. This account may also be charged with legal and consulting costs if such work is required by the Board. The fees are reviewed every three years to ensure they remain competitive, enabling Maritime Electric to attract quality people to serve as Board members.

Professional Services - $404,400 (2008), $390,500 (2009)

This account captures the costs associated with two main areas. The first is the annual external audit of the Company's financial statements. Secondly, included here are the non-capital related legal fees for various corporate, accounting, tax and environmental matters that the Company faces. Where legal costs are related to a specific capital project, they are charged there.

Regulation - $425,000 (2008), $522,700 (2009)

This account covers the annual assessment as provided by the Island Regulatory and Appeals Commission Act plus external costs associated with regulatory filings and related matters.

General Property (Net) - $232,000 (2008), $287,400 (2009)

This account collects the cost of operating and maintaining the Company's buildings at 180 Kent Street, West Royalty Service Centre, Sherbrooke and Roseneath Service Centers (net of rental income received). Included are costs for general maintenance, janitorial services, security, fire prevention, elevator repair and maintenance, snow removal, HVAC and other miscellaneous costs.

8.2 Summary

A summary of this section follows:

- Total General and Administrative operating expenses are forecast to be $10,759,100 for 2008 and $11,426,400 for 2009.

9.0 TRANSMISSION AND DISTRIBUTION EXPENSES

The Transmission and Distribution component of the Company's operations plays a significant role in ensuring system reliability and the delivery of customer service. Productivity and efficiency gains continue to be sought in the areas of improved work methods and materials, improved accuracy of field data, increased equipment automation and improved technical skills.

9.1 Transmission Expenses

These expenditures are for the operation and maintenance of those facilities which make up the Company's bulk energy delivery system, from the submarine cables to the input of the distribution system, (normally the high voltage terminals of the substation power transformers). The following Schedule shows Transmission Expenses for the period 2007 - 2009.

SCHEDULE 12			
Transmission Expenses 2007 – 2009 ($)			
Description	**2007 Actual**	**2008 Forecast**	**2009 Forecast**
Substations	25,681	29,400	39,100
Rights of Way	229,119	133,000	132,400
Line Maintenance	125,563	157,700	172,100
Line Control Devices	43,134	37,000	49,300
Engineering	65,960	79,900	83,600
Oasis Costs	-	120,200	214,700
Total	**489,457**	**557,200**	**691,200**

Substations – $29,400 (2008), $39,100 (2009)

This account provides for the maintenance and inspection of the Company's transmission substations. It includes labour, material, and transportation to maintain the transmission switches, insulators, bus connectors, and transformers.

Rights of Way – $133,000 (2008), $132,400 (2009)

This account provides for the maintenance and inspection of the Company's transmission rights of way. The majority of the expenditure in this account is for contract labour related to vegetation management which plays a vital role in system reliability and service quality. Transmission rights of way maintenance is scheduled on a cyclical basis such that all transmission lines receive attention at

least every eight to ten years. This results in variances on a year over year basis depending on the work cycle schedule.

Line Maintenance – $157,700 (2008), $172,100 (2009)

This account provides for the maintenance and inspection of over 600 km of transmission lines and is driven by preventative maintenance, storm damage and wear. Activities include repairing wires and connectors, replacing insulators, straightening poles and retightening guy wires.

Line Control Devices – $37,000 (2008), $49,300 (2009)

This account provides for the inspection and preventative maintenance of the transmission voltage circuit breakers and switches located in the Company's substations. The activities include inspection, replacing broken bushings, repainting and repairing control modules.

Engineering – $79,900 (2008), $83,600 (2009)

This account provides for the engineering support and analysis to operate and maintain the transmission system. Activities include power flow analysis, equipment monitoring, and engineering analysis to ensure optimal system operation.

OASIS – $120,200 (2008), $214,700 (2009)

This account provides for the tracking of costs associated with the operation of the Company's OASIS (Open Access Same-Time Information System) which reflects those costs recoverable from transmission system users under the Open Access Transmission Tariff. The Open Access Transmission Tariff has received interim approval from IRAC as of the date of this filing. The increase in 2009 reflects a full year of service for the OASIS.

9.2 Distribution Expenses

These accounts provide for the day-to-day operation and maintenance of the Company's distribution system. Included in these accounts are expenses relating to planned maintenance, breakdown and forced outage situations such as unforeseen equipment failure and outages due to storms. The Company

continues to seek to improve reliability while at the same time managing costs through planned maintenance. The following Schedule shows Distribution Expenses for the period 2007 - 2009.

SCHEDULE 13			
Distribution Expenses 2007 – 2009 ($)			
Description	**2007 Actual**	**2008 Forecast**	**2009 Forecast**
Substations	55,004	76,200	82,000
Rights of Way	621,737	616,600	633,500
Line Maintenance	854,246	1,032,100	1,111,400
Line Control Devices	37,308	63,200	63,800
Transformers	381,030	388,300	439,200
Meters	194,237	241,100	258,600
Communication	54,369	109,000	159,800
Supervisory SCADA	72,411	100,700	104,500
Engineering	81,851	104,500	100,000
Total	**2,352,193**	**2,731,700**	**2,952,800**

Substations - $76,200 (2008), $82,000 (2009)

This account provides for the inspection and maintenance of the Company's distribution substations. It includes labour, material, and transportation to maintain the switches, insulators, bus connectors, and the substation fence and ground grid. This account also includes vegetation management inside the substation fence.

Rights of Way – $616,600 (2008), $633,500 (2009)

This account provides for the inspection and maintenance of the rights of way for the Company's approximately 4,600 km of distribution lines. Cyclical tree trimming and clearing plays a significant role in reliability and service quality, particularly in the windy environment of PEI and results in variances from year to year. The majority of the expenditure in this account is for contract labour.

Line Maintenance – $1,032,100 (2008), $1,111,400 (2009)

This account provides for the maintenance and inspection of over 4,600 km of distribution lines, service lines to over 72,000 customers and 9,900 streetlights. Expenditures are driven by preventative maintenance, customer requests, and storm damage. Activities include repairing wires and connectors during no power calls, replacing fuses, straightening poles, tightening guy wires, repairs to

underground services and streetlight maintenance. This account also includes expenditures for small tool and equipment purchases, flame resistant clothing, and tool and equipment testing.

Line Control Devices – $63,200 (2008), $63,800 (2009)

This account provides for the maintenance and inspection of capacitors, voltage regulators and reclosers. The activities include inspection, replacing broken bushings, repainting and repairing control modules.

Transformers – $388,300 (2008), $439,200 (2009)

This account provides for the inspection and maintenance of over 30,000 distribution transformers, which includes both polemount and padmount units. The activities include inspection, testing, replacing broken bushings, repainting, and oil spill clean up.

Meters – $241,100 (2008), $258,600 (2009)

This account provides for the inspection and maintenance of over 72,000 revenue meters. Maintenance is driven by compliance with Measurement Canada rules and regulations and the number of units maintained changes year over year. Meters are sent to an outside lab for testing. The results of this testing determines if the sample set of meters meet industry standards or require replacement.

Communication – $109,000 (2008), $159,800 (2009)

This account collects the costs required to maintain radios installed in vehicles, hand held radios, fibre optic cables and power line carrier equipment to operate the Company's protection and control facilities and communications systems. The increase over 2008 reflects a one year maintenance agreement and license renewals as a result of the Communications system upgrade.

Supervisory SCADA - $100,700 (2008), $104,500 (2009)

This account collects the costs to maintain the SCADA system which controls and acquires data from the distribution and transmission system and transmits this data through the communication system to the Energy Control Centre.

Equipment inspection and maintenance and licensing fees account for the majority of the expenditures.

Engineering – $104,500 (2008), $100,000 (2009)

This account provides for the engineering support and analysis required to operate and maintain the distribution system. Activities include fuse coordination studies, power flow analysis to ensure lines are not overloaded or the voltage is too low, changing protection equipment settings to meet load growth and overall system oversight and planning not associated with capital projects.

9.3 Summary

A summary of this section follows:

- Total transmission system related operating expenses are forecast to be $557,200 for 2008 and $691,200 for 2009.
- Total distribution system related operating expenses are forecast to be $2,731,700 for 2008 and $2,952,800 for 2009.

10.0 ENERGY SUPPLY EXPENSES

10.1 Energy Supply Expenses

For 2009, Maritime Electric expects to purchase approximately 83 per cent of its energy supply requirement from NB Power and approximately 16 per cent under contract from four on-Island wind farms. The Company's generation facilities at the Charlottetown and Borden Plants continue to provide backup energy supply in the event of a system disturbance such as the loss of one of the submarine cables or a contract curtailment and are forecast to contribute approximately 1 per cent of the overall annual energy supply requirement.

The current purchases from NB Power are made through three main agreements: the Point Lepreau Unit Participation Agreement, the Dalhousie Unit Participation Agreement and the Energy Purchase Agreement ("EPA"). Both unit participation agreements extend for the life of the generating stations. The Energy Purchase Agreement is an eighteen month capacity and energy supply agreement expiring on September 30, 2009 (coincides with the completion of the refurbishment at Point Lepreau). Higher energy prices reflect current world fossil fuel prices and electricity market pricing. The EPA is currently undergoing an independent review and analysis by KnAP Energy Consultants.

Prices for energy and capacity purchases and estimates for on-Island generation costs were calculated using short-term world fossil fuel and electricity price futures. These costs have been incorporated into the Company's energy pricing model.

10.2 Net Purchased and Produced Energy Requirement

The Company's energy supply requirement, as shown in the following Schedule, is equal to the combined total of forecast energy sales, the energy requirements for Company use and an estimate for system losses. The Company must make provision for this through the combination of self-supply by generation at Charlottetown and Borden, purchases from other on-Island suppliers and purchases from off-Island sources.

SCHEDULE 14			
Net Purchased and Produced Energy 2007 - 2009 (MWh)			
	2007 Actual	2008 Forecast	2009 Forecast
Energy Sales	1,034,066	1,039,017	1,044,215
Company Use/System Losses	86,598	88,858	89,291
Total	**1,120,664**	**1,127,875**	**1,133,506**

10.3 Energy Supply by Source

The first step in determining the Company's energy supply requirement is to allocate the forecast NPP requirement, through a detailed hourly analysis, to arrive at an energy requirement for every hour of the year. To meet forecasted hourly loads, the first sources used are the Point Lepreau and Dalhousie Unit Participation Agreements as they are essentially take or pay agreements. Next to be included are the on-Island energy purchases from the wind farms under contract. Then an amount for firm energy purchases is used, usually contracted for as a component of the Energy Purchase Agreement at a prescribed minimum capacity factor. System energy purchases, under the Energy Purchase Agreement, are used to make up the balance of the forecasted hourly requirement. A small amount of energy production is forecast from the Company's Charlottetown and Borden Plants based upon operator training requirements, a provision for energy curtailments, system voltage support and management of the submarine cable load flows to ensure that operating limits are not exceeded.

Total energy supply costs are forecast to be $126,920,300 for 2008 and $136,660,700 for 2009. The following Schedule outlines the forecast cost of energy supply by source. Additional information on each supply source is also provided.

SCHEDULE 15			
Energy Supply Cost by Source 2007 – 2009 ($)			
Source	**2007 Actual**	**2008 Forecast**	**2009 Forecast**
Point Lepreau	11,165,579	10,181,500	10,761,500
Dalhousie	9,231,916	10,492,500	24,842,900
EPA - Firm Energy Purchases	14,606,645	40,652,800	38,538,800
EPA - System Energy Purchases	42,241,525	45,761,200	35,633,600
Charlottetown Plant	3,308,600	4,389,400	4,657,900
50 MW Combustion Turbine	124,597	755,000	3,555,800
Borden Plant	211,657	313,400	446,800
Wind	11,405,633	12,427,500	15,008,800
Ancillary Services	1,133,184	427,300	829,200
Other Purchases	4,956,719	1,397,900	2,171,800
Amortization of Deferred Charges	93,400	121,800	213,600
Total	**98,479,455**	**126,920,300**	**136,660,700**

Point Lepreau – $10,181,500 (2008), $10,761,500 (2009)

These forecast expenditures are based upon inputs from NB Power Nuclear and reflect Maritime Electric's 4.72 per cent participation in the costs to operate the facility, including provisions for decommissioning and irradiated fuel storage. The 18 month refurbishment of Point Lepreau commenced on April 1, 2008. Replacement of the Station's output during the refurbishment has been added to the Energy Purchase Agreement purchases.

Dalhousie – $10,492,500 (2008), $24,842,900 (2009)

These forecast expenditures are based upon inputs from NB Power Generation and reflect Maritime Electric's 6.67 per cent participation in the costs to operate the facility. A change in fuel pricing for 2009 accounts for the significant increase in costs compared to 2008. A capacity factor of approximately 82 per cent is forecast for 2008 and 2009.

EPA - Firm Energy Purchases – $40,652,800 (2008), $38,538,800 (2009)

Historically, firm energy purchases were used to supplement the Dalhousie and Point Lepreau purchases to provide the base load requirement for Maritime Electric and structured as a take or pay contract within the Energy Purchase

Agreement with a minimum monthly capacity factor of 85 per cent. This capacity factor provides flexibility in managing other purchases. For 2008 and 2009 this amount includes a portion of the energy required to replace the Company's share of the Point Lepreau output during its refurbishment.

EPA - System Energy Purchases - $45,761,200 (2008), $35,633,600 (2009)

System Energy is made up of 2 components: Secure Energy and Assured/Spot Market Energy. Both energy components can be curtailed based upon predefined situations, with varying notice periods for each of the energy components. System energy is expected to decrease by $10.0 million in 2009 reflecting increased purchases of wind energy, increased on-Island production and decreases in the price of purchased energy based on forecast future market prices.

Secure Energy is backed up by the 50 MW Combustion Turbine located at the Charlottetown Plant and is interruptible on 24 hours notice during the Winter period (November through March) and 7 days notice during the Summer period (April through October).

Assured/Spot Market Energy is backed up by the 60 MW of oil-fired generation at the Charlottetown Plant and is curtailable on either 7 days notice during the Summer period or 2 days notice during the Winter period This type of interruptible energy purchase allows Maritime Electric to better preserve the power boilers during the Summer and reduce deterioration and operating costs when not in operation. During the winter season the Charlottetown Plant is in warm standby mode and is capable of full output of 60 MW within forty-eight hours.

Charlottetown Plant – $4,389,400 (2008), $4,657,900 (2009)

The Charlottetown Plant's role is primarily one of back up for the submarine cables and to back up purchases of Assured/Spot Market Energy. It limits the exposure the Company faces during times that the Energy Purchase Agreement is curtailed as energy purchases during curtailment are only made when the price is below the generation cost at the Charlottetown Plant. The Plant may be

dispatched in December, during Maritime Electric's peak, to assist with load management on the submarine cables and to provide voltage support to the eastern end of the Province. The amount of energy produced by the facility varies significantly from year to year and is difficult to predict with any accuracy. A small amount of energy production is forecast based upon the tightening energy supply in the Maritime Provinces and for training of operating personnel in late December (the Company's peak) and in January to coincide with Nova Scotia and New Brunswick's peak load period.

The following Schedule outlines the expenditures necessary to maintain the facility and to produce energy on an as-needed basis.

SCHEDULE 16

Charlottetown Plant Operating Expenses 2007 – 2009 ($)

Description	2007 Actual	2008 Forecast	2009 Forecast
Buildings and Services	335,258	560,100	537,000
Plant Maintenance	881,486	1,158,700	980,800
Plant Operations	693,290	726,600	765,700
Superintendence	80,983	81,200	128,900
Energy Control Centre	369,634	518,600	500,800
Generation Fuel/Plant Heating	947,949	1,344,200	1,744,700
Total	**3,308,600**	**4,389,400**	**4,657,900**

50 MW Combustion Turbine - $755,000 (2008), $3,555,800 (2009)

The 50 MW combustion turbine is forecast to be used for peaking purposes with a provisional amount of generation that allows for periods of curtailment of contract energy. This facility backstops the Secure Energy component of the Energy Purchase Agreement. The forecast of operating expenses shown in Schedule 17 is consistent with the unit's capital project Application. The increased fuel supply cost in 2008 and 2009 reflects the forecast generation (provisional) during the outage at Point Lepreau.

SCHEDULE 17 50 MW Combustion Turbine Operating Expenses 2007 – 2009 ($)			
Description	**2007 Actual**	**2008 Forecast**	**2009 Forecast**
Buildings and Services	-	3,200	61,900
Plant Operating	16,206	39,400	90,000
Plant Maintenance	49,544	145,000	140,000
Generation Fuel	58,847	567,400	3,263,900
Total	**124,597**	**755,000**	**3,555,800**

Borden Plant – $313,400 (2008), $446,800 (2009)

These expenses are required to ensure the continued availability of the two generating units that serve to backstop the Company's purchase of Secure/Spot Market Energy and 10 minute operating reserve as required for reliability purposes. The Borden Plant is forecast to operate in 2008 and 2009 for maintenance and voltage support purposes only.

The following Schedule outlines the expenditures necessary to maintain the facility and to produce energy on an as-needed basis.

SCHEDULE 18 Borden Plant Operating Expenses 2007 – 2009 ($)			
Description	**2007 Actual**	**2008 Forecast**	**2009 Forecast**
Buildings and Services	-	2,000	-
Plant Operating	9,243	27,200	46,100
Plant Maintenance	129,577	117,600	154,900
Generation Fuel	72,837	166,600	245,800
Total	**211,657**	**313,400**	**446,800**

Wind – $12,427,500 (2008), $15,008,800 (2009)

Beginning in 2008, the Company will achieve the 15 per cent annual requirement of the Renewable Energy Act, with 52.5 MW of wind generation under contract.

PEI Energy Corporation – North Cape	10.5 MW
PEI Energy Corporation – East Point	30.0 MW
Suez – Norway	9.0 MW
Aeolus (Vestas) – Norway	3.0 MW
	52.5 MW

This output is based on historical trending of the energy output from the North Cape and Aeolus wind farms together with information provided for the other wind farms. The 13.5 MW of wind generation from North Cape and Aeolus is under contract with defined pricing methodologies while the additional 39 MW that came on line in 2007 is purchased as per the Minimum Purchase Price Regulations under the Renewable Energy Act. The increase in purchases in 2009 reflects the return to service of the units that were out of service for an extended period in 2008 for gearbox repairs.

Ancillary Services – $427,300 (2008), $829,200 (2009)

Other costs which arise in energy supply are ancillary services, transmission access through New Brunswick, and operations and maintenance costs associated with the Murray Corner and Memramcook substations in New Brunswick. Ancillary services such as load following, regulation, spinning reserve, non-spinning reserve, reactive power supply and voltage control are charged to Maritime Electric as set out in NB Power's Open Access Transmission Tariff.

The rates for ancillary services vary based on NB Power's costs to administer and supply these and on the Company's peak load in comparison to the peak load in the Maritimes as ancillary services are allocated based on the Company's share of the Maritime peak load.

Other Purchases – $1,397,900 (2008), $2,171,800 (2009)

This amount provides for a variety of miscellaneous charges, the largest of which is for the provision of off-Island energy purchases during times that the Energy Purchase Agreement has been curtailed and the purchase price of the replacement energy is less than on-Island generation costs.

Amortization of Deferred Charges – $121,800 (2008), $213,600 (2009)

This represents the amounts associated with the amortization of Maritime Electric's portion of the 1998 NB Power $450,000,000 write-down in the value of the Point Lepreau Nuclear Generating Station. Maritime Electric's portion was $5,976,506. At December 31, 2007, the unamortized balance was $2,614,339.

The accounting treatment applied to this is to amortize it over the useful life of the unit. With the refurbishment of Point Lepreau the estimated life of the Station is now set at 2035, resulting in an annual amortization expense of $93,400 which is proposed to continue to be recovered through the operation of the ECAM. The recovery of this amount is provided for in Section 47(4)(a)(ii) of the EPA.

The amount also includes the amortization of the Company's expenditures under its Demand Side Management Plan as approved by IRAC under Order UE08-02 dated February 21, 2008. The amount amortized is $28,400 for 2008 and $120,200 for 2009.

10.4 Summary

A summary of this section follows:

- The net purchased and produced energy required to meet forecast energy sales is 1,127,875 MWh in 2008 and 1,133,506 MWh in 2009.
- Total energy related operating expenses are forecast to be $126,920,300 for 2008 and $136,660,700 for 2009.

11.0 COSTS RECOVERABLE FROM CUSTOMERS

11.1 Costs Recoverable From Customers

Under the Base Rate Adjustment Regulations enacted in 2001 under the Maritime Electric Company Limited Regulation Act, Maritime Electric was required to defer 90 per cent of energy related costs in excess of $0.05 per kWh and permitted to recover them in the following year. At December 31, 2003 that amount was $20,783,600, representing costs that Maritime Electric would have been able to recover under the Maritime Electric Company Limited Regulation Act and the Base Rate Adjustment Regulations in 2004, had they remained in effect.

As part of the transition to cost of service regulation, provision was made in the EPA to allow the Company to recover these costs. Section 47(4)(a)(i) of the EPA provides for the recovery of these costs over such period of time and on such terms and conditions as the Commission considers just and reasonable. The balance of deferred Costs Recoverable From Customers at December 31, 2007 was $13,983,600. In Order UE06-08, the Commission ordered the Company to increase the annual amortization to $2,000,000 for 2008 and each year thereafter until otherwise ordered by the Commission.

11.2 Summary

A summary of this section follows:

- Management proposes that the terms of Order UE06-08 continue to apply with respect to the amortization of Costs Recoverable From Customers.

12.0 FINANCIAL OBJECTIVES

12.1 Financial Objectives

Meeting the following objectives will enable the Company to compete for financing at rates that allow it to continue to invest in the energy delivery infrastructure while providing service at the lowest possible cost to electricity consumers on Prince Edward Island:

(i) Maintain a debt ratio in the range of 55 per cent to 60 per cent and a common equity ratio in the range of 40 per cent to 45 per cent;

(ii) Maintain coverage on total debt interest in the range of 2.4 times to 2.6 times; and

(iii) Provide a return to the Shareholder commensurate with that of other Atlantic Canadian investor-owned utilities.

12.2 Capital Structure and Interest Coverage

Maritime Electric finances its investment in infrastructure with a combination of debt (short-term debt and first mortgage bonds) and Shareholder equity. To minimize the total cost of this financing, a balance between the two (referred to as the target capital structure) is required.

The target capital structure is designed to provide the necessary interest coverage and flexibility to ensure the financial viability of the Company. Under the EPA, the minimum common equity component of the Company's capital structure is set at 40 per cent. To ensure that the Company's capital structure remains flexible and able to adapt to changing market conditions, it is proposed that the common equity component of the Company's capital structure be permitted to remain in the range of 40 per cent to 45 per cent.

The target capital structure of Maritime Electric is based upon:

- The embedded and forecast cost of debt;
- The cost of common equity;
- The requirements of the EPA (Maritime Electric must maintain a minimum of 40 per cent common equity in its capital structure);
- Providing sufficient flexibility to allow for future external financing; and

- Maintaining adequate debt interest coverage ratios to ensure access to debt markets.

The following Schedule shows the Company's year-end capital structure for the period 2007 - 2009.

SCHEDULE 19 Capital Structure 2007 - 2009 (%)			
	2007 Actual	**2008 Forecast**	**2009 Forecast**
Debt	59.9	58.4	57.8
Equity	40.1	41.6	42.2
Total	**100.0**	**100.0**	**100.0**

Debt financing is less expensive than equity financing, however, there is a balance between the two that must be reached. Excessive amounts of debt leads lenders to view their investment as higher risk, requiring higher returns (interest) on the debt, thereby increasing costs. Excessive amounts of debt cause equity investors to require a higher rate of return. Conversely, while increasing equity levels will reduce the debt holders risk (and required return) it increases the total cost of capital due to the higher return required on the thicker equity ratio. The investor return required (both debt and equity) reflects the investor's perception of business and financial risk associated with the investment.

The Corporate Credit Rating is a measure of the Company's overall credit worthiness and is based upon an independent analytical review by Standard & Poor's of the Company's earnings, financial position and an analysis of Company-specific and industry-related issues. The Company's Corporate Credit Rating is BBB^{+} (stable outlook), two notches above the minimum rating the markets consider to be investment grade. Maritime Electric's long-term debt is currently rated at A (investment grade). Debt issues under $100 million are generally held by a small number of investors, are generally considered illiquid, and are only attractive to institutional investors, typically insurance companies who are "buy and hold" investors.

Common equity is comprised of the Shareholder's investment in common shares and retained earnings. The level in the capital structure must be such that the resulting earnings provide for debt interest coverages within the targeted range, without undue burden on consumers.

Maritime Electric is a wholly-owned subsidiary of Fortis Inc., however, its financial performance must reflect the risk profile of a publicly-traded Company. It must stand on its own financial performance and perform on a basis similar to other enterprises with a similar risk profile. Utilities in Canada are characterized by the following:

- Medium investment risk,
- Assured dividend stream, and
- Modest capital appreciation.

If Maritime Electric is to compete for funds on a basis similar to other utilities it must maintain a similar risk profile. One of the comparisons is the ability to pay dividends. The inability to pay dividends on a consistent basis may result in considerably more restrictive covenants for new debt issues, limitations on the term for which investors are prepared to lend, and ultimately a higher cost of issuing debt. The regular payment of dividends also assists in maintaining an appropriate balance between debt and equity thus minimizing rate impacts to customers. The following Schedule shows Maritime Electric's dividends for the period 2007 - 2009.

SCHEDULE 20			
Dividends 2007 – 2009 ($)			
	2007 Actual	2008 Forecast	2009 Forecast
Total	3,000,000	3,500,000	5,000,000

The target interest coverages are designed to ensure that the Company's long-term debt remains competitive with that of other similarly rated companies, enabling it to compete for funds in the capital markets. Interest coverage ratios are used by credit rating agencies and debt lenders to assess the adequacy of the Company's capital structure and associated investment risk. The earnings

before interest and taxes (EBIT) coverage measure is calculated by dividing operating income and allowance for funds used during construction by total interest and debt issue costs to determine the number of "times" that operating income can cover the interest costs. Management believes that the target debt interest coverage of 2.4 times to 2.6 times meets the requirements established earlier, and is appropriate for the Company's debt rating.

12.3 Amortization of Fixed Assets

The purpose of amortization of fixed assets is to recover the cost of these assets over their useful life. Amortization is an estimate based upon the best information available. Maritime Electric uses the straight line method of amortization, based on the estimated average service lives of the assets. Only ½ year of amortization expense is recorded in the first year of capitalization of the asset. Customer contributions toward the cost of construction are netted against the cost of fixed assets for amortization purposes. The fixed asset amortization rates used by Maritime Electric since 2003 represent the rates proposed for 2009.

SCHEDULE 21	
Fixed Asset Amortization Rates 2003 - 2009	
Category	**(%)**
Plant	2.5
Substations	3.2
Transmission	2.3
Distribution	3.0
Communications	6.0
Transportation	7.5
General Property Other	3.2
Computer Hardware and Software	13.8
Supervisory System	6.0

The forecast fixed asset amortization expense for 2008 and 2009 is $11,804,200 and $12,440,700 respectively.

12.4 Interest Costs

This section focuses on the costs associated with financing through the use of debt (short-term and long-term).

12.4.1 Long-Term Debt Interest

Through its Trust Deed, Maritime Electric has mortgaged or pledged, either by way of a first and specific charge or by way of a floating charge, all of its properties and assets as security for its first mortgage bonds. The most recent debt issue was a $60.0 million, 30 year first mortgage bond issue with an interest rate of 6.054%. This issue was completed in April 2008 and the debt issue costs will be amortized over the term of the issue.

The following Schedule shows the Company's long-term debt and annual interest expense for 2007 - 2009.

SCHEDULE 22

Long -Term Debt 2007 – 2009 ($)

		Annual Expense		
Amount	**Interest Rate (%)**	**2007 Actual**	**2008 Forecast**	**2009 Forecast**
15,000,000	12.000	1,800,000	1,800,000	1,800,000
12,000,000	11.500	1,380,000	1,380,000	1,380,000
15,000,000	8.550	1,282,500	1,282,500	1,282,500
15,000,000	7.570	1,135,500	1,135,500	1,135,500
15,000,000	8.625	1,293,750	1,293,750	1,293,750
20,000,000	8.920	1,784,000	1,784,000	1,784,000
60,000,000	6.054	-	2,724,300	3,632,400
Total		**8,675,750**	**11,400,050**	**12,308,150**

12.4.2 Short-Term Debt Interest

The short-term financing requirements for Maritime Electric include energy-related costs, operating and maintenance costs, tax installments, inventory purchases and payroll costs. To the extent that these are not covered by internally generated funds, Maritime Electric maintains a $50.0 million operating line with its bank. The Company benefits from the combined borrowing power of the Fortis group of companies as it is able to borrow funds at a lower interest rate than it would be able to negotiate

on its own. Through the continued use of Banker's Acceptances (BA's), the Company is able to further reduce its annual borrowing costs versus the use of its operating line.

The results of the financial forecast indicate that at December 31, 2008 and December 31, 2009, Maritime Electric will have $8,272,100 and $13,116,200 in short-term debt outstanding respectively with short-term interest costs of $1,388,600 and $465,500 respectively.

12.4.3 Allowance for Funds Used During Construction

Maritime Electric provides for the cost of financing construction work in progress by including an Allowance for Funds Used During Construction (AFUDC) as an addition to the cost of property constructed. The rate used reflects the cost of the Company's debt and equity financing. This allowance is charged to operations through amortization over the service life of the related assets ensuring that the cost is paid, not just by those who are customers during the period of construction, but by those customers who benefit from the asset during its useful life.

Based on the forecast capital expenditures for 2008 and the proposed 2009 Capital Budget, the forecast of AFUDC for 2008 and 2009 is $250,000 and $227,100 respectively.

12.5 Return on Average Common Equity

Maritime Electric is proposing an allowed return on average common equity of 9.75%. The requested return represents, for the 2009 test year, a reduction of 25 basis points from the 10.0% maximum 2008 return allowed by the Commission in Order UE08-01 dated January 24, 2008. A return of 9.75% would be, in Maritime Electric's view, at the lower end of the range of reasonableness. However, in light of the impact on customers of the significant increase in energy costs in 2009, Maritime Electric proposes a return of 9.75%.

Maritime Electric continues to face higher business risk relative to the other Atlantic Canada electric utilities. In Order UE06-03, the Commission agreed with

that conclusion, subject to the caveat that Maritime Electric's business risks were mitigated somewhat through the operation of the ECAM. It is important to note that Nova Scotia Power has since received approval for a Fuel Adjustment Mechanism to expedite the collection of increasing energy related costs. Maritime Electric's fundamental risks have not changed materially since the Commission's June 2006 decision; its relative business risk, arising from its small size, island location and relatively undiversified economy, was not an issue in the 2008 Rate Application on which Order UE08-01 was based.

Maritime Electric's target common equity ratio remains at 45%. However, the actual common equity ratio has been declining, from 47% in 2004 to 40% in 2007, i.e., approximately equal to the legislated minimum. The equity ratio in 2009 is expected to be approximately 42.2% (assuming an approval of the Company's proposal to rebase the ECAM). The pressure on the equity ratio (increase in debt ratio) from 2004 is partly due to the relatively high 2005 – 2006 capital expenditures for generation capacity and partly due to the required financing of deferred energy costs. The significant increase in energy costs in 2007 – 2009 is a reflection of the increase in purchased energy costs due to the transition to market based pricing by NB Power, the cost of replacement energy during the Point Lepreau refurbishment and the fuel pricing change at Dalhousie in 2009. All other things equal (i.e., no change in business risk or interest rate levels), a higher debt ratio (lower equity ratio) means higher financial risk and a higher cost of equity.

Maritime Electric's Standard & Poor's ("S&P") corporate credit rating remains at BBB+ (stable outlook), confirmed in November 2007. S&P continues to view Maritime Electric as having a stand-alone credit profile at about mid "BBB", with its actual BBB+ rating reflecting the support of the Company's parent, Fortis Inc., which is rated A by S&P. The return allowed should be sufficient to permit the Company to achieve a stand-alone financial position equivalent to a BBB+ rating, to ensure that Fortis Inc. is not subsidizing Maritime Electric and its customers.

Interest coverage ratios are the best measure of the Company's ability to meet its debt obligations. In Maritime Electric's view, a target EBIT interest coverage ratio

in the range of 2.4 to 2.6 times is reasonable.[5] Schedule 23 compares Maritime Electric's actual and forecast EBIT coverage ratios for 2005-2009. The Schedule shows that the Company's interest coverage ratios have been weakening, and are expected to fall short of the target range in 2009, even if Maritime Electric earns its proposed return of 9.75%.

SCHEDULE 23				
Interest Coverage Ratio 2005 – 2009 (Times)				
2005 Actual	2006 Actual	2007 Actual	2008 Forecast	2009 Forecast
2.5	2.5	2.4	2.3	2.3

The persistent decline of pre-tax interest coverage to the 2.3 times level is a concern to Maritime Electric. A lower return than the 9.75% requested would result in further interest coverage deterioration, which could put pressure on the corporate credit rating, increasing the cost to Maritime Electric to borrow funds to finance its capital and operating expenditures.

In its November 9, 2007 report, S&P stated that Maritime Electric's financial profile "suffers from somewhat weak cash generation" and that "funds from operation (FFO) interest coverage[6] has been less than 3 times for the past three years." From 2004-2006, Maritime Electric's FFO interest coverage averaged 2.6 times, declining from 2.9 times in 2004 to 2.4 times in 2006. In 2007, FFO interest coverage was 2.8 times, with the improvement largely due to future (deferred) income taxes related to the ECAM. The Company's forecasts for 2008 and 2009 show that FFO interest coverage is expected to remain just below the 3.0 times level cited by S&P. The forecast higher level of FFO interest coverage relative to 2004-2006 continues to be driven by the temporary level of future (non-cash) income taxes. In the absence of the temporary "lift" provided by future income taxes, FFO interest coverage at the requested return would be materially weaker.

There has been a significant change in the interest rate environment since Maritime Electric's last rate Application. The spread of the U.S. subprime

[5] EBIT interest coverage is calculated as the sum of operating income and AFUDC divided by total (short-term and long-term debt) interest.
[6] Net Income from Continuing Operations plus Depreciation and Amortization and Future Income Taxes divided by Total Debt Outstanding.

mortgage crisis to the Canadian economy and capital markets has resulted in a "flight to quality", as investors have moved from higher risk securities to default-free government securities. The "flight to quality" has depressed the yields on long-term Canadian bonds.

The forecast yield on the benchmark long-term (30-year) Government of Canada bond at the time of Maritime Electric's last rate application was approximately 4.7%.[7] Based on the recent Consensus Economics, *Consensus Forecasts* (June 2008), the forecast 30-year Canada bond yield is approximately 4.05%,[8] equal to the current yield.

Were Maritime Electric's allowed return tied solely to the trend in long-term government bond yields, as is the case in other Canadian regulatory jurisdictions, the decline in forecast long-term government bond yields would produce a decline in the allowed return of approximately 0.50%.[9] However, while long-term Government of Canada bond yields have fallen since Maritime Electric's last rate application, utility bond yields have actually increased. At the end of September 2007, the yield on long-term Canadian A rated utility bonds was 5.83%, compared to the then prevailing 30-year Canada bond yield of 4.44%, a difference of 1.4%.[10] The corresponding yields at the end of June 2008 were 6.02% and 4.08%, a difference of close to 1.95%. The higher utility bond yields today compared to 2007 point to an increase, not a decrease, in the cost of equity.

The 10.0% allowed ROE requested by Maritime Electric in its last Application reflected a risk premium above A rated utility bond yields of approximately 4.2 percentage points (10.0% - 5.83%). A similar spread above the utility bond yields in the current capital market environment supports an increase in the

[7] The September 2007 Consensus Forecast anticipated 10-year Government of Canada bond yields of 4.5% and 4.8% in December 2007 and September 2008 respectively, for an average of 4.65%. The September 2007 yield spread between 10-year and 30-year Canada bonds was 0.7%, for an indicated 30-year Canada bond yield forecast of 4.7% (4.65 + 0.07).
[8] The June 2008 forecasts are for 10-year Government of Canada bond yields of 3.6% and 3.9% in September 2008 and June 2009 respectively (average of 3.75%). Adding the recent yield spread between 10- and 30-year Canada bonds of 0.35% to the 10-year bond forecast results in a 30-year Canadian bond yield forecast of 4.05%.
[9] A number of regulatory jurisdictions rely on automatic adjustment formulas which change allowed ROEs by 75% of the change in forecast 30-year Canada bond yields, without regard to other relevant factors that impact the cost of equity. Under these formulas, a reduction in the forecast 30-year Canada bond yield from 4.72% to 4.05% would reduce the allowed ROE by 0.5% (75% x (4.05%- 4.72%)).
[10] Yields on series of A rated Canadian utility bonds based on data from RBC Capital Markets.

allowed ROE to 10.2% (6.0% + 4.2%). Recognizing, however, the forecast increase in energy costs in 2008 and 2009, Maritime Electric is proposing an allowed return of 9.75%, a level the Company views as the lower end of the range of reasonableness.

Maritime Electric's allowed return on equity should provide a return to the Shareholder commensurate with those of other investor-owned Atlantic Canadian utilities. A return of 9.75% is reasonable for Maritime Electric in this regard, recognizing that Maritime Electric is of higher risk than the other two Atlantic Province investor-owned electric utilities. The Schedule below summarizes the earned returns on equity for the other Atlantic Province electric utilities over the past four years (2004-2007).

SCHEDULE 24		
Earned Returns On Equity 2004 - 2007 (%)		
Year	**Newfoundland Power**	**Nova Scotia Power**
2004	10.1	10.0
2005	9.6	8.7
2006	9.1	9.7
2007	8.6	9.7
Average	**9.35**	**9.53**

The actual average return earned by Newfoundland Power and Nova Scotia Power of 9.45% is approximately 0.30% below the requested 9.75% return. A maximum return on equity 0.30% above the average earned return of Newfoundland Power and Nova Scotia Power is reasonable considering Maritime Electric's relatively higher risk.

12.6 Summary

A summary of this section follows:

The Company's financial objectives are as follows:

(i) Maintain a debt ratio in the range of 55 per cent to 60 per cent and a common equity ratio in the range of 40 per cent to 45 per cent;

(ii) Maintain coverage on total debt interest in the range of 2.4 times to 2.6 times; and

(iii) Provide the Shareholder with a return commensurate with that of other Atlantic Canadian investor-owned utilities.

In support of these objectives, the Company proposes the following:

- The amortization rates for 2009 be the same as those used since 2003;
- The forecast amortization expense for fixed assets in 2008 is $11,804,200 and $12,440,700 in 2009;
- Interest expense on long-term debt is forecast to be $11,400,050 in 2008 and $12,308,150 in 2009;
- Short-term interest costs for 2008 and 2009 are forecast to be $1,388,600 and $465,500 respectively;
- The Allowance For Funds Used During Construction for 2008 and 2009 is forecast to be $250,000 and $227,100 respectively; and
- A Return on Average Common Equity of 9.75 per cent for 2009 is just and reasonable.

13.0 FINANCIAL FORECAST

13.1 Financial Forecast Process

The components of the financial forecast process will be discussed separately.

- Energy Sales Forecast;
- Capital Expenditures;
- Revenue;
- Operating Expenses;
- Financing Costs;
- Income Taxes; and
- Revenue Requirement;

The financial forecast process incorporates other variables such as dividend payments, short-term interest rates, inventory requirements and cash flow requirements. The results are presented to the Company's Board of Directors for approval.

13.2 Energy Sales Forecast

The results of the energy sales forecast are used in the preparation of the Capital and Operating Budgets as well as the forecast of electric revenue.

13.3 Capital Expenditures

The capital expenditures forecast uses the energy sales forecast as a prime input. The projected increase in energy sales and the number of customers drive expenditures for system infrastructure. The balance of the capital expenditures is based on corporate needs in terms of ensuring the necessary infrastructure to continue to provide a high level of customer service. The capital expenditures are categorized according to their amortization rate and the appropriate amortization expense (1/2 in the first year) is calculated. The following Schedule shows the capital expenditures used in the financial forecast for 2008 - 2009.

SCHEDULE 25 Schedule of Capital Expenditures 2008 – 2009 ($)		
	2008 Forecast	**2009 Forecast**
Corporate	1,421,000	1,519,000
Generation		
Charlottetown Plant	1,651,000	1,072,000
Borden Plant	97,000	664,000
Transmission & Distribution		
Distribution	13,803,000	13,082,000
Transmission	16,191,000	753,000
Sub-total		
Allowance for Funds Used During Construction	250,000	227,000
General Expense Capitalized	2,012,000	2,331,000
Less: Contributions	(15,235,000)	(250,000)
Net Capital Expenditures	**20,190,000**	**19,398,000**

13.4 Revenue

There are two components to the calculation of revenue. The first component is Basic Rate Revenue which is calculated using forecast energy sales at existing Basic Rates. The second component is Other Income which is comprised of transmission revenue, connection fees, late payment charges and miscellaneous revenue. Schedule 26 shows the revenue derived from existing Basic Rates for 2008 - 2009.

SCHEDULE 26 Energy Sales and Revenue Forecast 2008 - 2009 (Existing Basic Rates)		
	2008 Forecast	**2009 Forecast**
Energy Sales by Class – (MWh)		
Residential	437,334	439,958
General Service I	367,460	369,298
General Service II	5,361	5,495
Large Industrial	150,013	150,357
Small Industrial	70,757	70,828
Street Lighting	5,862	5,939
Unmetered	2,230	2,340
Total Energy Sales	**1,039,017**	**1,044,215**

Revenue by Class		
Residential	62,574,400	63,810,300
General Service I	47,031,800	47,555,900
General Service II	688,700	719,100
Large Industrial	10,205,600	10,260,000
Small Industrial	7,759,700	7,770,300
Street Lighting	1,883,100	1,907,300
Unmetered	306,700	317,900
Total Electric Revenue	130,450,000	132,340,800
Other Income		
Transmission Revenue	806,000	1,586,500
Late Payment Charges	506,700	480,900
Connection Fees	463,400	488,700
Miscellaneous Revenue	416,200	461,000
Total Other Income	2,192,300	3,017,100
Total Revenue	**132,642,300**	**135,357,900**

The following Schedule shows the revenue derived from Basic Rates as a result of the proposed rebasing.

SCHEDULE 27		
Energy Sales and Revenue Forecast 2008 - 2009 (Proposed Rebasing)		
	2008 Forecast	**2009 Forecast**
Energy Sales by Class – (MWh)		
Residential	437,334	439,958
General Service I	367,460	369,298
General Service II	5,361	5,495
Large Industrial	150,013	150,357
Small Industrial	70,757	70,828
Street Lighting	5,862	5,939
Unmetered	2,230	2,340
Total Energy Sales	**1,039,017**	**1,044,215**
Revenue by Class		
Residential	62,574,400	67,744,200
General Service I	47,031,800	50,579,300
General Service II	688,700	762,400
Large Industrial	10,205,600	10,933,800
Small Industrial	7,759,700	8,280,500
Street Lighting	1,883,100	2,027,800
Unmetered	306,700	338,200
Total Electric Revenue	**130,450,000**	**140,666,200**
Other Income		
Transmission Revenue	806,000	1,586,500
Late Payment Charges	506,700	510,300
Connection Fees	463,400	523,100
Miscellaneous Revenue	416,200	461,000
Total Other Income	2,192,300	3,080,900
Total Revenue	**132,642,300**	**143,747,100**

13.5 Operating Expenses

Operating expenses used in the financial forecast are taken from this Evidence and are presented in the following Schedule.

SCHEDULE 28		
Operating Expenses 2008 – 2009 ($)		
	2008 Forecast	**2009 Forecast**
Energy (Net of ECAM)[11]	75,784,200	84,313,000
Distribution	2,731,700	2,952,800
Transmission	557,200	691,200
General and Administrative	10,759,100	11,426,400
Total	**89,832,200**	**99,383,400**

13.6 Financing

Management has assumed the continued short-term financing through its operating line for the forecast period.

13.7 Income Taxes

Maritime Electric uses the liability method of accounting for income taxes. Under this method future income taxes are recognized based on the expected future tax consequences of differences between the carrying amount of Balance Sheet items and their corresponding tax basis, using the enacted and substantively enacted income tax rates for the years in which the differences are expected to reverse. Maritime Electric maximizes its tax deductions to minimize cash flow, reduce interest costs and minimize the impact on customers. Schedule 29 shows Maritime Electric's effective corporate income tax rates for the period 2007 - 2009 reflecting the series of additional income tax rate reductions enacted by the federal government in the last year.

SCHEDULE 29			
Effective Corporate Income Tax Rates 2007 – 2009 (%)			
	2007 Actual	**2008 Forecast**	**2009 Forecast**
Effective Tax Rate	39.2	32.6	33.4

13.8 Revenue Requirement

The revenue requirement is comprised of the following:

- Forecast energy sales for the year (Section 7.2);

[11] Excludes amortization of Point Lepreau and DSM Deferred Charges.

- The forecast cost of generating or purchasing energy to meet energy sales (Section 10.3);
- The forecast cost of delivering the energy to customers (the "wires" cost) (Sections 9.1 and 9.2);
- The forecast amount of general and administrative expenses (Section 8.8);
- The amortization of Costs Recoverable From Customers (Section 11);
- Forecast fixed asset amortization expense (Section 12.3);
- Forecast financing cost amortization expense (Section 12.4);
- Forecast short-term and long-term interest expense (Section 12.4);
- Income taxes (Section 13.7); and
- Return on average common equity (Section 12.5).

Schedule 30 outlines the projected Revenue Requirement for 2008 - 2009 at $132,642,300 and $143,747,100 respectively. Based on the results of the financial forecast this results in a Return on Average Common Equity of 9.75 per cent in 2009.

SCHEDULE 30		
Revenue Requirement 2008 – 2009 ($)		
	2008 Forecast	**2009 Forecast**
Operating Expenses (Net of ECAM)	89,832,200	99,383,400
Amortization of Costs Recoverable from Customers	2,000,000	2,000,000
Interest Expense	12,538,700	12,546,500
Amortization Expense - Financing Costs	2,400	3,900
Amortization Expense - Fixed Assets	11,804,200	12,440,700
Amortization Expense – DSM Costs	28,400	120,200
Amortization Expense - Point Lepreau Writedown	93,400	93,400
Income Tax Expense	5,328,200	5,737,700
Return on Average Common Equity	11,014,800	11,421,300
Total	**132,642,300**	**143,747,100**

13.9 Financial Forecast Results

The financial forecast uses the inputs previously outlined in this Evidence. A summary of the results (prepared in accordance with GAAP) of the Company's financial forecast for 2008 and 2009, is shown in Appendix 2.

13.10 Summary

A summary of the results of this section follows:

- Maintain a debt ratio in the range of 55 per cent to 60 per cent and a common equity ratio in the range of 40 per cent to 45 per cent;
- Maintain coverage on total debt interest in the range of 2.4 times to 2.6 times;
- Provide a return to the Shareholder commensurate with that of other Atlantic Canadian investor-owned utilities;
- The amortization rates currently in effect are to be used for 2009; and
- Maritime Electric proposes a Return on Average Common Equity of 9.75 per cent.

14.0 IMPACT OF PROPOSAL ON CUSTOMERS' COSTS

14.1 Background

The Company is proposing a Return on Average Common Equity of 9.75% for 2009 reflecting the comparison of Maritime Electric's risk profile with other investor owned utilities in Atlantic Canada. In particular it reflects the impact of rebasing the ECAM and placing an increased percentage of the energy cost recovery in Basic Rates.

The effect of rebasing is to shift the collection of energy related costs from the ECAM to Basic Rates. For a rural residential customer using 650 kWh's per month the forecast annual costs under the Company's proposals in respect of Return on Average Common Equity and the rebasing of the ECAM are shown in the following Schedule.

SCHEDULE 31 Forecast Annual Cost for Rural Residential Customer (2009 – 2012)				
	2009	**2010**	**2011**	**2012**
Annual Cost for Rural Residential Customers Using 650 kWh's per month ($)	1,568.63	1,665.94	1,709.55	1,734.23
Percentage Annual Increase (%)	7.46	6.20	2.62	1.44

15.0 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 April 1, 2009 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;

AND UPON considering the Application as well as the Evidence of the Company;

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

1. The Company remove the Point Lepreau replacement energy costs from the ECAM calculation for the period January 1, 2009 to September 30, 2009 and that these costs be amortized back into the ECAM calculation over a ten year period commencing on October 1, 2009.

2. The base rate per kWh used in the Energy Cost Adjustment Mechanism ("ECAM") be set as follows:

	Current	April 1, 2009	April 1, 2010	April 1, 2011	April 1, 2012
ECAM Base Rate per kWh ($)	0.0673	0.0770	0.0900	0.1000	0.1100

3. The Basic Rates be increased to reflect the rebasing as follows:

	April 1, 2009	April 1, 2010	April 1, 2011	April 1, 2012
Basic Rate Increase – Rebasing (%)	8.40	9.80	6.90	7.40

4. The Company be ordered to file an updated report on ECAM rebasing by November 15, 2010; and

5. The maximum allowed Return on Average Common Equity be set at 9.75 per cent for 2009.

DATED at Charlottetown this ____ day of ____, 2008

BY THE COMMISSION:

_____

Maurice Rodgerson, Chair

_____

Anne Petley, Commissioner

_____

John Broderick, Commissioner

_____

Ernest Arsenault, Commissioner

APPENDIX 1

Schedule of Basic Rates, Fees and Charges – April 1, 2009

The Goods and Services Tax

The Goods and Services Tax applies to all rates and charges in Sections N, O-1 and O-2, with the exception of Late Payment Charges in Section O-2.

The Goods and Services Tax applies to the amount of contribution to be paid by the customer, based on the rates and charges in Sections O-3 and O-4.

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 base cost for purchased and produced electricity is $0.077/kWh net produced and purchased.

The rate adjustment per kilowatt hour sold and applied in each month will be calculated as follows:

1. Determine the total cost of purchasing and producing electricity in the second month preceding the billing month.

2. Determine the net kilowatt hours of purchased and produced energy in the second month preceding the billing month.

3. Multiply the quantity of energy determined in (2) above by the base cost of $0.077/kWh to determine the base cost of energy.

4. Subtract the base cost of energy determined in (3) above from the sum of the cost determined in (1) above to calculate the excess or deficiency of the cost of purchased energy.

5. Add the excess (or deficiency) of the cost of purchased and produced energy calculated in (4) above to the corresponding excess (deficiency) costs on the Balance Sheet and divide by twelve to determine the average excess (deficiency) cost of purchased and produced energy to be collected in the billing month.

6. Divide the amount calculated in (5) above by the total energy sold by the Company in the second month preceding the billing month to determine the rate adjustment required in cents per kilowatt hour sold and which will be applied in the billing month. The rate adjustment will be calculated to the nearest two decimal places (four decimal places on the dollar).

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:	11.78¢ per kWh for first 2000 kWh per Billing Period 9.14¢ 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:	11.78¢ per kWh for first 2000 kWh per Billing Period 9.14¢ 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:	11.78¢ per kWh for first 2000 kWh per Billing Period 9.14¢ 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:	11.78¢ per kWh for first 2000 kWh per Billing Period 9.14¢ per kWh for balance kWh per Billing Period

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

General Service Rate Schedules

General Service I

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:	14.72¢ per kWh for first 5000 kWh per Billing Period 9.27¢ 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:	14.72¢ per kWh for first 5000 kWh per Billing Period 9.27¢ per kWh for balance kWh per Billing Period

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

General Service Rate Schedules – Cont'd

General Service II

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 and who use electricity as the only source of energy for cooking, space heating, water heating and all other services.

Billing Demand

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

Rate	***(Code 250)***
Service Charge:	$24.57 per billing period
Demand Charge:	No charge for first 20 kW or less per billing period. Charge for the balance of kilowatts per billing period: the lesser of (a) $5.68 per kilowatt or (b) 2.84¢ times the number of kilowatt hours consumed in the billing period.
Energy Charge:	14.72¢ per kWh for first 5000 kWh per billing period 10.86¢ per kWh for next 5000 kWh per billing period 10.34¢ per kWh for balance kWh per billing period

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

General Service Rate Application Guidelines

General Service I and II

General Service I and II 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;

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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: 14.40¢ per kWh for first 100 kWh per kW of billing demand per month
6.75¢ 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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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: 5.30¢ 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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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:

- 8.01¢ 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) 7.57¢ per kWh.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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 on 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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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 +1.33¢/kWh.
Off peak price = incremental cost during off peak hours +0.44¢/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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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 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 +1.33¢/kWh.
Off peak price = incremental cost during off peak hours +0.4¢/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 0.065¢/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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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 1⅝% 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 1⅝% 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 $1.13 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).

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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:	6.74¢ 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:	7.73¢ per kWh for all kWh in the first block per month 6.23¢ 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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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: 14.72¢ per kWh of estimated consumption

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

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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 4.64¢ per watt of connected load per week. The minimum charge is for a period of one (1) week.
(Code 850)

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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:
14.72¢ per kWh of estimated consumption

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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	157.71	13.14	735	656
*175 Watt	7500	200.75	16.73	736	881
*250 Watt	11100	279.28	23.27	737	1210
*400 Watt	19800	359.00	29.92	738	1906
High Pressure Sodium					
70 Watt	5500	157.71	13.14	730	389
100 Watt	8500	200.36	16.70	731	553
150 Watt	14400	286.83	23.90	732	799
200 Watt	19800	314.90	26.24	720	1033
250 Watt	27000	391.04	32.59	733	1283
400 Watt	45000	459.77	38.31	734	1886
High Pressure Sodium Floodlight					
250 Watt	-	373.56	31.13	753	-
400 Watt	-	466.92	38.91	754	-
Metal Halide Floodlight					
250 Watt	-	392.23	32.69	755	-
400 Watt	-	485.59	40.47	756	-
1000 Watt	-	840.48	70.04	757	-
Poles:					
Wood Pole			4.38	610	-
Concrete Pole			7.96	611	-

*These charges are applicable to existing fixtures only.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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	157.71	13.14	635	656
*175 Watt	7500	200.75	16.73	636	881
*250 Watt	11100	279.28	23.27	637	1210
*400 Watt	19800	391.04	32.59	638	1906
High Pressure Sodium					
70 Watt Lantern	5500	572.99	47.75	639	389
70 Watt	5500	157.71	13.14	630	389
100 Watt	8500	200.75	16.73	631	553
150 Watt	14400	286.83	23.90	632	799
200 Watt	19800	343.77	28.65	620	1033
250 Watt	27000	391.04	32.59	633	1283
400 Watt	45000	459.77	38.31	634	1886

*These charges are applicable to existing fixtures only.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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	64.10	5.34	-	-	-
200 Watt	128.97	10.75	-	-	-
300 Watt	192.80	16.07	-	-	-
500 Watt	309.20	25.77	-	-	-
Mercury Vapour					
100 Watt	77.46	6.46	-	-	-
125 Watt	95.21	7.93	645	745	656
175 Watt	128.97	10.75	646	746	881
250 Watt	177.97	14.83	647	747	1210
400 Watt	281.66	23.47	648	748	1906
700 Watt	479.63	39.97	-	-	-
1000 Watt	681.17	56.76	-	-	-
Low Pressure Sodium					
90 Watt	73.37	6.11	752	752	-
135 Watt	104.75	8.73	751	751	-
180 Watt	131.49	10.96	749	749	869
High Pressure Sodium					
70 Watt	63.42	5.29	640	740	389
100 Watt	83.83	6.99	641	741	553
150 Watt	112.95	9.41	642	742	779
200 Watt	155.33	12.94	650	750	1033
250 Watt	179.03	14.92	643	743	1283
400 Watt	281.66	23.47	644	744	1886
1000 Watt	676.28	56.36	-	-	-
Metal Halide Lighting					
70 Watt	57.41	4.78	-	758	390
100 Watt	78.46	6.54	-	759	533
175 Watt	131.61	10.97	-	760	894
250 Watt	169.00	14.08	-	761	1148
400 Watt	276.45	23.04	-	762	1878
1000 Watt	639.77	53.31	-	763	4346
LED Lighting					
100 Watt	60.36	5.03	-	764	410

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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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 per billing period
Energy Charge: 14.72¢ per kWh for first 5000 kWh per billing period
9.27¢ 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.

Energy Cost Adjustment Mechanism: This rate is subject to the Energy Cost Adjustment Mechanism.

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 During _____ 2009

The following adjusted rates include a per kWh Energy Cost Adjustment of: TDB

Rate Code	Lamp Wattage	Type		Annual kWh	Monthly kWh		Basic Rates	ECAM Adjustment		Adjusted Rates
620	200	HPS	St Lights - Rented	1033	86	$	28.65	TBD	$	28.65
630	70	HPS	St Lights - Rented	389	32	$	13.14	TBD	$	13.14
631	100	HPS	St Lights - Rented	553	46	$	16.73	TBD	$	16.73
632	150	HPS	St Lights - Rented	799	66	$	23.90	TBD	$	23.90
633	250	HPS	St Lights - Rented	1283	106	$	32.59	TBD	$	32.59
634	400	HPS	St Lights - Rented	1886	157	$	38.31	TBD	$	38.31
635	125	MV	St Lights - Rented	656	54	$	13.14	TBD	$	13.14
636	175	MV	St Lights - Rented	881	73	$	16.73	TBD	$	16.73
637	250	MV	St Lights - Rented	1210	101	$	23.27	TBD	$	23.27
638	400	MV	St Lights - Rented	1906	158	$	32.59	TBD	$	32.59
639	70	Lanterns	City Lanterns - Rented	389	32	$	47.75	TBD	$	47.75
640	70	HPS	St Lights - Owned	389	32	$	5.29	TBD	$	5.29
641	100	HPS	St Lights - Owned	553	46	$	6.99	TBD	$	6.99
642	150	HPS	St Lights - Owned	779	65	$	9.41	TBD	$	9.41
643	250	HPS	St Lights - Owned	1283	107	$	14.92	TBD	$	14.92
644	400	HPS	St Lights - Owned	1886	157	$	23.47	TBD	$	23.47
645	125	MV	St Lights - Owned	656	55	$	7.93	TBD	$	7.93
646	175	MV	St Lights - Owned	881	73	$	10.75	TBD	$	10.75
647	250	MV	St Lights - Owned	1210	101	$	14.83	TBD	$	14.83
648	400	MV	St Lights - Owned	1906	159	$	23.47	TBD	$	23.47
650	200	HPS	St Lights - Ow[illegible]	1033	86	$	12.94	TBD	$	12.94
720	200	HPS	Yard Li[illegible] - R[illegible]nte	1033	86	$	26.24	TBD	$	26.24
730	70	HPS	Yard [illegible]ghts - Re[illegible]nted	389	32	$	13.14	TBD	$	13.14
731	100	HPS	[illegible] Lights - [illegible]ented	553	46	$	16.70	TBD	$	16.70
732	150	HPS	Yard [illegible]ights - Rented	799	66	$	23.90	TBD	$	23.90
733	250	HPS	[illegible] Lights - Rented	1283	106	$	32.59	TBD	$	32.59
734	400	HPS	Yard Lights - Rented	1886	157	$	38.31	TBD	$	38.31
735	125	MV	Yard Lights - Rented	656	54	$	13.14	TBD	$	13.14
736	175	MV	Yard Lights - Rented	881	73	$	16.73	TBD	$	16.73
737	250	MV	Yard Lights - Rented	1210	100	$	23.27	TBD	$	23.27
738	400	MV	Yard Lights - Rented	1906	158	$	29.92	TBD	$	29.92
740	70	HPS	Yard Lights - Owned	389	32	$	5.29	TBD	$	5.29
741	100	HPS	Yard Lights - Owned	553	46	$	6.99	TBD	$	6.99
742	150	HPS	Yard Lights - Owned	779	65	$	9.41	TBD	$	9.41
743	250	HPS	Yard Lights - Owned	1283	107	$	14.92	TBD	$	14.92
744	400	HPS	Yard Lights - Owned	1886	157	$	23.47	TBD	$	23.47
745	125	MV	Yard Lights - Owned	656	55	$	7.93	TBD	$	7.93
746	175	MV	Yard Lights - Owned	881	73	$	10.75	TBD	$	10.75
747	250	MV	Yard Lights - Owned	1210	101	$	14.83	TBD	$	14.83
748	400	MV	Yard Lights - Owned	1906	159	$	23.47	TBD	$	23.47
749	180	LPS	Yard Lights - Owned	869	72	$	10.96	TBD	$	10.96
750	200	HPS	Yard Lights - Owned	1033	86	$	12.94	TBD	$	12.94
751	135	LPS	Yard Lights - Owned	730	61	$	8.73	TBD	$	8.73
752	90	LPS	Yard Lights - Owned	521	43	$	6.11	TBD	$	6.11
753	250	Flood	Yard Lights - Rented	1283	107	$	31.13	TBD	$	31.13
754	400	Flood	Yard Lights - Rented	1886	157	$	38.91	TBD	$	38.91
755	250	Halide	Yard Lights - Rented	1148	95	$	32.69	TBD	$	32.69
756	400	Halide	Yard Lights - Rented	1878	156	$	40.47	TBD	$	40.47
757	1000	Halide	Yard Lights - Rented	4346	362	$	70.04	TBD	$	70.04
758	70	Halide	St Lights - Owned	390	32	$	4.78	TBD	$	4.78
759	100	Halide	St Lights - Owned	533	44	$	6.54	TBD	$	6.54
760	175	Halide	St Lights - Owned	894	74	$	10.97	TBD	$	10.97
761	250	Halide	St Lights - Owned	1148	95	$	14.08	TBD	$	14.08
762	400	Halide	St Lights - Owned	1878	156	$	23.04	TBD	$	23.04
763	1000	Halide	St Lights - Owned	4346	362	$	53.31	TBD	$	53.31
764	100	LED	St Lights - Owned	410	34	$	5.03	TBD	$	5.03

Schedule of "Adjusted Rates"

Maritime Electric Company Limited

Applied to Bills During _____ 2009

The following adjusted rates include a per kWh Energy Cost Adjustment of: TBD

Rate Code		Basic Rates	ECAM Adjustment	Adjusted Rates
110	**Residential Urban**			
	Service Charge	$ 24.57	TBD	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1178	TBD	$ 0.1178
	Energy Charge per kWh for balance kWh	$ 0.0914	TBD	$ 0.0914
130	**Residential Rural**			
	Service Charge	$ 26.92	TBD	$ 26.92
	Energy Charge per kWh first 2,000 kWh	$ 0.1178	TBD	$ 0.1178
	Energy Charge per kWh for balance kWh	$ 0.0914	TBD	$ 0.0914
131	**Residential Seasonal**			
	Service Charge	$ 26.92	TBD	$ 26.92
	Energy Charge per kWh first 2,000 kWh	$ 0.1178	TBD	$ 0.1178
	Energy Charge per kWh for balance of kWh	$ 0.0914	TBD	$ 0.0914
133	**Residential Seasonal Option**			
	Service Charge	$ 37.50	TBD	$ 37.50
	Energy Charge per kWh first 2,000 kWh	$ 0.1178	TBD	$ 0.1178
	Energy Charge per kWh for balance of kWh	$ 0.0914	TBD	$ 0.0914
232	**General Service I**			
	Service Charge	$ 24.57	TBD	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	TBD	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	TBD	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1472	TBD	$ 0.1472
	Energy Charge per kWh for balance of kWh	$ 0.0927	TBD	$ 0.0927
233	**General Service I - Seasonal Operators Option**			
	Service Charge	$ 24.57	TBD	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	TBD	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	TBD	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1472	TBD	$ 0.1472
	Energy Charge per kWh for balance of kWh	$ 0.0927	TBD	$ 0.0927
250	**General Service II**			
	Service Charge	$ 24.57	TBD	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	TBD	$ -
	Demand Charge - per kW for balance of kW:		TBD	
	(a) per kilowatt or	$ 5.68	TBD	$ 5.68
	(b) the number of kilowatt hours consumed in the period times	$ 0.0284	TBD	$ 0.0284
	Energy Charge per kWh for first 5,000 kWh	$ 0.1472	TBD	$ 0.1472
	Energy Charge per kWh for next 5,000 kWh	$ 0.1086	TBD	$ 0.1086
	Energy Charge per kWh for balance of kWh	$ 0.1034	TBD	$ 0.1034
320	**Small Industrial**			
	Demand Charge - per kW	$ 7.46	TBD	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1440	TBD	$ 0.1440
	Energy Charge per kWh for balance of kWh	$ 0.0675	TBD	$ 0.0675
310	**Large Industrial**			
	Demand Charge per kW	$ 14.50	TBD	$ 14.50
	Energy Charge per kWh	$ 0.0530	TBD	$ 0.0530
340	**Long Term Contract**			
	Demand Charge per kW	$ 15.51	TBD	$ 15.51
	Energy Charge per kWh	$ 0.0674	TBD	$ 0.0674
330	**Short Term Contract**			
	Demand Charge - per kW	$ 16.79	TBD	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.0773	TBD	$ 0.0773
	Energy Charge per kWh for balance of kWh in the month	$ 0.0623	TBD	$ 0.0623

Schedule of "Adjusted Rates"

Maritime Electric Company Limited

Applied to Bills During _____ 2009

The following adjusted rates include a per kWh Energy Cost Adjustment of: TBD

		Basic Rates	ECAM Adjustment	Adjusted Rates
610	Pole Rental -Wood	$ 4.38	TBD	$ 4.38
611	Pole Rental -Concrete	$ 7.96	TDB	$ 7.96
	Unmetered Rates (based on 100 watt fixture)			
810	8 Hour Lighting per kWh	$ 0.1472	TBD	$ 0.1472
	Minimum Charge	$ 11.67	TDB	$ 11.67
820	12 Hour Lighting per kWh	$ 0.1472	TBD	$ 0.1472
	Minimum Charge	$ 11.67	TBD	$ 11.67
830	24 Hour Lighting per kWh	$ 0.1472	TBD	$ 0.1472
	Minimum Charge	$ 11.67	TBD	$ 11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category		
850	Outdoor Christmas Lighting - 4.64¢ per watt of connected load per week			
234	Customer Owned Outdoor Recreational Lighting			
	Service Charge	$ 24.57	TBD	$ 24.57
	Energy Charge per kWh for first 5,000 kWh	$ 0.1472	TBD	$ 0.1472
	Energy Charge per kWh for balance of kWh	$ 0.0927	TBD	$ 0.0927

Short Term Unmetered Rates	Currently no customers in this rate category		
Energy Charge:			
per kWh of estimated consumption	$ 0.1472	TBD	$ 0.1472

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	0	594.94

The Goods and Services Tax

The Goods and Services Tax applies to all rates and charges in Sections N, O-1 and O-2, with the exception of Late Payment Charges in Section O-2.

The Goods and Services Tax applies to the amount of contribution to be paid by the customer, based on the rates and charges in Sections O-3 and O-4.

O. Fees and Charges

Service Call Fee

A service call fee of $42.44 is applicable to the following services:

Change from temporary to permanent service.

Reconnection of service, including reconnection for accounts disconnected for nonpayment, installations where services have been upgraded, connections that do not require installation of a secondary service, and connection of services that require a meter reading only.

If the meter is removed for testing at the customer's request and the test results indicate the meter accuracy is within the allowable limits.

Each addition to an existing unmetered account.

A service call fee <u>is not</u> applicable to the following services:

Reconnection of service disconnected as a result of fire or other casualty or any incident not the fault of the customer.

Transfer of service under the Landlord Service Plan.

Installation of area lights.

Additions to street lighting or traffic control light Accounts.

Disconnection of service.

Service to a premises to facilitate changes of a minor nature such as meter removal for replacement of siding.

Connection and Reconnection Fees

A connection fee of $75.08 is charged for all initial service connections including metered temporary facilities.

For multiple metered installations, e.g., apartment buildings, the $75.08 fee applies to the service for the common area. If there is no separate service for the common area, this charge applies to the first service connected. The remainder of the initial connections in multiple metered premises will be charged the service call fee and not the connection fee.

Connection of a mobile home to Maritime Electric facilities that requires installation of an Overhead Secondary Service is considered to be an initial installation.

A seasonal reconnection fee of $89.90 is applicable to the reconnection of an existing seasonal service to Maritime Electric facilities if the reconnection is for the same occupants of the premises.

After Hours Fee

If a customer requests service outside Maritime Electric's normal working hours, an after hours fee will be charged in addition to the connection or service call fee.

The after hours fee is $61.67 for jobs requiring two (2) person hours or less, including travel. For jobs requiring more than two (2) person hours, the after hours fee is set at Maritime Electric's incremental cost of providing the service.

Non Sufficient Funds Charge

The charge for non sufficient funds is $16.50.

Late Payment Charge

The late payment charge for all customers is 1.65% per month (effective annual rate 21.70% per annum or 0.05382% compounded daily rate).

Late Payment Charge - Cont'd

The minimum late payment charge is 55¢. If an account is less than $4.00 in arrears, no late payment charge is applied.

Extension of Overhead Facilities Charges

Extension of Overhead Facilities Refunds

	Type of Original Contribution:	
Type of New Account Connected	**Single-Phase**	**Three-Phase**
Single-Phase	90 meters times the average per meter construction charge	90 meters times half of the average per meter construction charge
Three-Phase	90 meters times the average per meter construction charge	90 meters times the average per meter construction charge

Optional Facilities Charges

Maintenance Charge for Optional Facilities:

16.5% of the total estimated construction cost of the optional facilities.

Nonstandard Service Entrances:

Location	$ 72.42
Pole	$ 347.62
Anchor	$ 141.95

Facilities to Non-Fixed Premises

Pole	$ 347.62
Anchor	$ 141.95

APPENDIX 2

Financial Statements

APPENDIX 2
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Earnings

	Actual 2007	Forecast 2008	Forecast 2009
Revenue			
Revenue Requirement	$ 130,109,055	$ 132,642,300	$ 143,747,100
Amortization - Costs Recoverable From Customers (Pre-2004)	(1,300,000)	(2,000,000)	(2,000,000)
Net Revenue	128,809,055	130,642,300	141,747,100
Operating Expenses (net of ECAM)	88,737,752	89,832,200	99,383,400
Amortization - Fixed Assets	11,113,506	11,804,200	12,440,700
Amortization - Deferred Charges	93,400	121,800	213,600
Operating Income	28,864,397	28,884,100	29,709,400
Financing Costs	11,645,612	12,541,100	12,550,400
Earnings Before Income Taxes	17,218,785	16,343,000	17,159,000
Income Taxes	6,746,488	5,328,200	5,737,700
Net Earnings	$ 10,472,297	$ 11,014,800	$ 11,421,300
Return on Average Common Equity (%)	10.20%	10.00%	9.75%

APPENDIX 2
Maritime Electric
Financial Results (Actual and Forecast)
Balance Sheets

	Actual 2007	Forecast 2008	Forecast 2009
ASSETS			
Fixed Assets			
Property, plant and equipment	$ 397,166,640	$ 431,319,800	$ 448,918,200
Less: Accumulated amortization	126,324,420	136,082,900	145,625,200
	270,842,220	295,236,900	303,293,000
Other Long-Term Assets			
Costs Recoverable from Customers (Pre-2004)	13,983,600	11,983,600	9,983,600
Costs Recoverable from Customers (Post-2003)	14,915,119	32,514,800	47,722,100
Deferred Charges	2,614,939	2,825,100	2,924,500
	31,513,658	47,323,500	60,630,200
Current Assets			
Cash	510,428	0	0
Accounts Receivable	18,888,041	19,323,700	20,528,200
Materials and Supplies	4,839,276	5,500,000	5,600,000
Prepaid Expenses	890,411	780,600	776,700
Income Tax Deposit	5,921,580	5,921,600	5,921,600
	31,049,736	31,525,900	32,826,500
TOTAL ASSETS	$ 333,405,614	$ 374,086,300	$ 396,749,700
SHAREHOLDER'S EQUITY AND LIABILITIES			
Shareholder's Equity			
Common Shares	$ 31,100,681	$ 31,100,700	$ 31,100,700
Retained Earnings	75,340,496	82,855,300	89,276,600
	106,441,177	113,956,000	120,377,300
Long-term Debt	92,000,000	152,000,000	152,000,000
Other Long-Term Liabilities			
Future income taxes	17,376,905	19,350,000	22,000,000
Contributions	14,079,821	28,272,800	27,246,200
	31,456,726	47,622,800	49,246,200
Current Liabilities			
Bank indebtedness	0	2,100	1,200
Short-term borrowings	66,955,000	8,270,000	13,115,000
Future income taxes	8,217,326	12,024,100	15,270,300
Accounts payable and accrued liabilities	28,335,385	40,211,300	46,739,700
	103,507,711	60,507,500	75,126,200
TOTAL SHAREHOLDER'S EQUITY AND LIABILITIES	$ 333,405,614	$ 374,086,300	$ 396,749,700
Capital Structure - Year End			
Total Debt	59.9%	58.4%	57.8%
Common Equity	40.1%	41.6%	42.2%
	100.0%	100.0%	100.0%

APPENDIX 2
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Cash Flows

	Actual 2007	Forecast 2008	Forecast 2009
Cash Flow from Operating Activities			
Net Earnings	$ 10,472,297	$ 11,014,800	$ 11,421,300
Add (deduct) non-cash items:			
Amortization - Fixed Assets	11,113,506	11,804,200	12,440,700
Amortization - Deferred Charges	93,400	121,800	213,600
Future income taxes	5,402,860	5,779,900	5,896,100
Changes in non-cash working capital	(15,558,081)	(4,710,400)	(7,979,400)
	11,523,982	24,010,300	21,992,300
Cash Flow From Financing Activities			
Issuance of long-term debt	0	60,000,000	0
Contributions	3,511,826	15,235,000	250,000
Payment of dividends	(3,000,000)	(3,500,000)	(5,000,000)
	511,826	71,735,000	(4,750,000)
Cash Flow from Investing Activities			
Expenditures for Fixed Assets (Net)	(27,138,636)	(37,572,800)	(22,086,400)
Increase (Decrease) in Cash	(15,102,828)	58,172,500	(4,844,100)
Bank Indebtedness, Beginning of Year	(51,341,744)	(66,444,572)	(8,272,100)
Bank Indebtedness, End of Year	($66,444,572)	($8,272,100)	($13,116,200)

APPENDIX 3

Monthly ECAM Calculations January 1, 2008 to December 31, 2009

Appendix 3
Monthly ECAM Calculation - Janaury 1, 2008 to December 31, 2009

A. Energy Cost Adjustment Mechanism

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
1. Purchased Energy Costs	6,255,407	5,836,231	7,052,374	6,418,300	7,249,982	8,438,989	10,940,488	11,053,639	6,098,958	6,110,313	6,067,654	6,710,772	88,233,107
2. Lepreau Energy Costs	990,500	1,002,851	969,201	755,116	869,782	905,405	697,017	632,068	948,758	815,767	762,825	832,213	10,181,503
3. Dalhousie Energy Costs	845,270	874,107	854,955	864,426	845,939	807,704	883,868	934,406	936,330	984,160	808,146	853,174	10,492,486
4. Generation Fuel Costs-PEI Plants	123,293	200,586	84,025	58,767	36,575	66,850	5,132	5,364	11,442	97,042	97,562	1,291,482	2,078,119
5. PEI Plant Operating Costs	259,857	229,316	221,698	240,266	235,650	224,815	211,775	224,475	356,935	379,286	380,714	420,919	3,385,706
6. Amortization - Point Lepreau & DSM Deferred Charges	7,783	12,516	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150	121,800
7. Renewable Energy Costs	1,349,184	1,137,756	1,144,390	656,698	541,444	509,785	540,911	880,064	1,096,003	1,521,423	1,286,392	1,763,460	12,427,511
	9,831,294	9,293,363	10,336,793	9,003,724	9,789,522	10,963,699	13,289,341	13,740,166	9,458,576	9,918,141	9,413,443	11,882,171	126,920,232
8. Net 2007 Purchased & Produced Energy - kWh (NPP)	100,559,146	94,787,149	97,158,871	85,415,893	87,985,233	86,120,719	98,193,058	94,801,953	88,859,978	94,424,304	94,779,621	104,788,877	1,127,874,802
9. Base Rate/kWh	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673
10. Base Energy Costs	6,767,631	6,379,175	6,538,792	5,748,490	5,921,406	5,795,924	6,608,393	6,380,171	5,980,277	6,354,756	6,378,669	7,052,291	75,905,974
11. Difference Between Actual & Base Energy Costs	3,063,663	2,914,188	3,798,001	3,255,234	3,868,116	5,167,774	6,680,949	7,359,994	3,478,300	3,563,386	3,034,774	4,829,879	51,014,258
12. ECAM Balance Dec 31, 2006 - to be rebated	(1,341,006)	(1,241,006)	(1,141,006)	(1,041,006)	(941,006)	(841,006)	(741,006)	(641,006)	(541,006)	(441,006)	(341,006)	(241,006)	(1,341,006)
13. Amount rebated to customers	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,200,000
14. Balance to be rebated	(1,241,006)	(1,141,006)	(1,041,006)	(941,006)	(841,006)	(741,006)	(641,006)	(541,006)	(441,006)	(341,006)	(241,006)	(141,006)	(141,006)
15. Post 2006 ECAM Opening Balance	16,256,124	17,837,536	19,532,008	21,871,633	23,643,628	24,862,433	27,102,865	30,564,388	34,232,065	33,889,816	33,174,194	31,972,741	16,256,124
16. Additions/(Reductions)	3,063,663	2,914,188	3,798,001	3,255,234	3,868,116	5,167,774	6,680,949	7,359,994	3,478,300	3,563,386	3,034,774	4,829,879	51,014,258
17. Rebated/(Collected) From Ratepayer	(1,482,251)	(1,219,717)	(1,458,375)	(1,483,240)	(2,649,310)	(2,927,343)	(3,219,425)	(3,692,318)	(3,820,548)	(4,279,008)	(4,236,227)	(4,146,774)	(34,614,535)
18. Balance Post 2006 ECAM	17,837,536	19,532,008	21,871,633	23,643,628	24,862,433	27,102,865	30,564,388	34,232,065	33,889,816	33,174,194	31,972,741	32,655,847	32,655,847
19. General Ledger Closing Balance	16,596,530	18,391,002	20,830,627	22,702,622	24,021,427	26,361,859	29,923,382	33,691,059	33,448,810	32,833,188	31,731,735	32,514,841	32,514,841
20. Cost to Residential Customer (650 kWh/Month)	$ 8.06	$ 8.65	$ 9.45	$ 10.83	$ 19.73	$ 22.41	$ 23.31	$ 26.08	$ 27.83	$ 30.32	$ 31.23	$ 31.44	$ 249.33

A. Energy Cost Adjustment Mechanism

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
21. Purchased Energy Costs	8,206,973	7,183,357	6,017,442	5,750,424	5,870,033	6,727,504	8,118,863	7,220,250	6,832,059	4,906,820	5,114,675	5,225,131	77,173,531
22. Lepreau Energy Costs	785,922	725,579	834,803	802,552	827,479	852,145	877,071	901,868	926,534	1,052,143	1,073,561	1,101,735	10,761,391
23. Dalhousie Energy Costs	2,250,455	2,066,159	2,255,990	2,130,343	2,186,185	2,129,582	2,185,423	2,185,043	1,404,051	1,738,504	2,127,679	2,183,521	24,842,934
24. Generation Fuel Costs-PEI Plants	997,790	659,551	659,551	122,010	122,010	6,000	543,541	543,541	6,000	122,010	124,698	1,347,755	5,254,459
25. PEI Plant Operating Costs	285,441	285,441	287,052	286,471	282,005	282,398	282,005	281,969	282,362	281,969	285,441	283,494	3,406,048
26. Amortization - Point Lepreau Deferred Charge	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	213,600
27. Renewable Energy Costs	1,421,327	1,449,914	1,535,851	1,298,886	1,146,558	865,199	672,497	852,360	1,110,690	1,570,224	1,305,791	1,779,476	15,008,774
	13,965,708	12,387,802	11,608,489	10,408,487	10,452,070	10,880,628	12,697,202	12,002,830	10,579,495	9,689,470	10,049,645	11,938,912	136,660,737
28. Net 2008 Purchased & Produced Energy - kWh (NPP)	99,219,062	91,539,825	93,092,873	86,935,683	89,461,761	91,808,833	100,154,091	94,636,921	89,727,769	95,325,942	96,047,964	105,555,257	1,133,505,980
29. Base Rate/kWh	0.0673	0.0673	0.0673	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077
30. Base Energy Costs	6,677,443	6,160,630	6,265,150	6,694,048	6,888,556	7,069,280	7,711,865	7,287,043	6,909,038	7,340,098	7,395,693	8,127,755	84,526,598
31. Difference Between Actual & Base Energy Costs	7,288,265	6,227,172	5,343,339	3,714,439	3,563,514	3,811,348	4,985,337	4,715,787	3,670,457	2,349,372	2,653,952	3,811,157	52,134,139
32. ECAM Balance Dec 31, 2006 - to be rebated	(141,006)	(41,006)	-	-	-	-	-	-	-	-	-	-	(141,006)
33. Amount rebated to customers	100,000	41,006	-	-	-	-	-	-	-	-	-	-	141,006
34. Balance to be rebated	(41,006)	-	-	-	-	-	-	-	-	-	-	-	-
35. Post 2006 ECAM Opening Balance	32,655,847	36,110,019	38,580,211	39,902,423	40,835,179	41,615,157	42,673,574	44,949,314	46,975,637	47,875,317	47,276,928	46,900,021	32,655,847
36. Additions/(Reductions)	7,288,265	6,227,172	5,343,339	3,714,439	3,563,514	3,811,348	4,985,337	4,715,787	3,670,457	2,349,372	2,653,952	3,811,157	52,134,139
37. Rebated/(Collected) From Ratepayer	(3,834,092)	(3,756,981)	(4,021,126)	(2,781,684)	(2,783,535)	(2,752,931)	(2,709,596)	(2,689,464)	(2,770,776)	(2,947,761)	(3,030,860)	(2,989,119)	(37,067,927)
38. Balance Post 2006 ECAM	36,110,019	38,580,211	39,902,423	40,835,179	41,615,157	42,673,574	44,949,314	46,975,637	47,875,317	47,276,928	46,900,021	47,722,059	47,722,059
39. General Ledger Closing Balance	36,069,013	38,580,211	39,902,423	40,835,179	41,615,157	42,673,574	44,949,314	46,975,637	47,875,317	47,276,928	46,900,021	47,722,059	47,722,059
40. Cost to Residential Customer (650 kWh/Month)	$ 28.96	$ 27.92	$ 27.56	$ 20.03	$ 20.78	$ 21.06	$ 21.29	$ 20.65	$ 20.57	$ 21.48	$ 22.72	$ 23.04	$ 276.07