MARITIME ELECTRIC
A FORTIS COMPANY

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The Island Regulatory and Appeals Commission

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October 3, 2014

Mr. Mark Lanigan
Director, Technical & Regulatory Services
Island Regulatory and Appeals Commission
PO Box 577
501 – 134 Kent Street
Charlottetown PE C1A 7L1

Dear Mr. Lanigan:

Responses to Interrogatories from Provincial Government
Maritime Electric 2015 Capital Budget

Please find attached the Company's response to the Interrogatories filed by the Island Regulatory and Appeals Commission with respect to the 2015 Capital Budget.

Yours truly,

MARITIME ELECTRIC

Steven Loggie

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

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Enclosure

Q-1 Within Section 3 – <u>Boiler Insulation Replacement Improvements</u> there is a stated provisional amount of $57,000 for this activity. Is there any estimate as to the scope of asbestos insulation remaining in the facility and potential future costs to remove it?

<u>Response:</u>

Q-1 The Charlottetown Plant asbestos abatement program has been in place for a number of years. The provisional amount of $57,000 is based upon our past experience with this abatement program which allows for the safe removal and disposal of asbestos when repairs to equipment are required. A recent tender for the removal of all known asbestos remaining within the Charlottetown Plant resulted in an estimated total removal cost of $1.7 million. It was determined that it would be more cost effective to proceed as in the past number of years and complete the remaining asbestos abatement during the decommissioning of the plant.

Q-2 It is noted in G-3 under Charlottetown Plant Turbine-Generator Projects that the installation of a snow hood is proposed for CT3. The reasoning provided for the necessity of this capital improvement is that the unit does not operate enough to keep temperatures in the stack and vent silencers elevated to the point that rust and corrosion would be negated. What were the annual hours of operation for CT3 over the past two years and what were the anticipated annual hours of its operation?

Response:

Q-2 In 2012 and 2013, CT3 ran for approximately 391 hours and 107 hours respectively. In 2014 CT3 is forecast to run approximately 141 hours and, year to date, it has run 95 hours. In 2015 CT3 is forecast to run for 537 hours.

Q-3 Similar to Interrogatory #1, in regards to the proposed budget of $64,000 for <u>Turbine Insulation (Asbestos) Replacement</u>, what is the scope of asbestos insulation remaining in this unit and potential costs for future removal operations?

<u>Response:</u>

Q-3 Please see the response to Interrogatory #1.

Q-4 There is a proposed budget of $251,000 assigned to supplying <u>In-Line Fuel Heaters for CT1 and CT2</u> (Borden Plant). What is the breakdown of costs for equipment and installation for this activity? (Note: Reliability of power generating equipment in cold weather operation is essential.)

<u>Response:</u>

Q-4 The budget breakdown for this project is as follows:

Heater and controls	$60,000
New enclosure	25,000
Piping	30,000
Insulation	10,000
Room heating	2,000
Electric service (MECL)	25,000
Electric service (contractor)	30,000
MECL Labour and Supervision	27,200
Sub-Total	**$209,200**
Contingency (20% - rounded)	41,800
Total	**$251,000**

The 20% contingency amount is larger than what is typically sought due to the nature of the retrofit required for this project.

Q-5 Within D-3, there is a proposed budget of $1,000,000 for Street and Yard Lighting to replace high pressure sodium (HPS) and mercury vapour lighting fixtures that had reached their useful life with more energy efficient LED models. What is the expected average annual energy savings (kWh) per fixture with this retrofit and the accruing simple payback period?

Response:

Q-5 The Company's Proposal to convert existing high pressure sodium (HPS) and mercury vapour (MV) fixtures to energy efficient light emitting diode (LED) fixtures was approved by IRAC on January 15, 2014. As noted in the Proposal, as LED technology develops and fixture prices decrease, the level of customer interest in adopting these new lighting options has continued to increase. In response to customer interest and recognizing the reductions in energy consumption that could be achieved by supporting the conversion to LED, the Company will commence the 10-year conversion plan in 2015.

As indicated in the table on the next page, upon full conversion of the primary classes of HPS and MV fixtures to LED, annual energy consumption for street lights will be reduced by approximately 2.7 million kWh resulting in estimated annual savings to customers of almost $650,000 based upon rates currently in effect. Please see the attached schedule for further detail.

MARITIME ELECTRIC COMPANY, LIMITED

ENERGY SAVINGS - CONVERSION OF MV AND HPS TO LED STREET LIGHTING

HPS Street and Area Lighting	70 W HPS	100 W HPS			150 W HPS	Total kWh Consumption	Total Savings to Customers	Line
kWh per year at 4,100 hours annually[1]	389	553			799			1
Approximate Number of Fixtures in System[2]	5,200	2,500			1,400			2
kWh Consumption (rounded)	2,022,800	1,382,500			1,118,600	4,523,900		3
MV Street and Area Lighting			125 W MV	175 W MV	250 W MV			
kWh per year at 4,100 hours annually[1]			656	881	1,210			4
Approximate Number of Fixtures in System[2]			400	15	45			5
kWh Consumption (rounded)			262,400	13,215	54,450	330,065		6
LED Street and Area Lighting	43 W LED	50 W LED	72 W LED	72 W LED	100 W LED			
kWh per year at 4,100 hours annually[1]	176	205	295	295	410			7
Approximate Number of Fixtures in System[2] - line 2 + line 5	5,200	2,500	400	15	1,445			8
kWh Consumption (rounded)	915,200	512,500	118,000	4,425	592,450	2,142,575		9
Annual Electricity Consumption Reduction (line 3 + line 6 - line 9)	1,107,600	870,000	144,400	8,790	580,600	2,711,390		10

Notes
1. Number of watts per fixture (including ballast) times 4,100 hours divided by 1,000
2. Assuming full conversion from current HPS and MV Street and Area Lights

CUSTOMER RATE SAVINGS[3] - CONVERSION OF MV AND HPS TO LED STREET LIGHTING

Current Fixture Type and Size	70 W HPS	100 W HPS	125 W MV	175 W MV	150 W HPS	250 W MV		
Replacement LED Fixture	43 W LED	50 W LED	72 W LED	72 W LED	100 W LED	100 W LED		
Current Monthly Rates for HPS and MV Fixtures	$ 14.59	$ 18.55	$ 14.44	$ 18.37	$ 26.49	$ 25.54		11
Approved Monthly Interim Rates for Replacement LED Fixtures	11.03	11.42	12.69	12.69	14.77	14.77		12
Monthly Savings per Fixture	$ 3.56	$ 7.13	$ 1.75	$ 5.68	$ 11.72	$ 10.77		13
	12	12	12	12	12	12		14
Annual Savings per Fixture	$ 42.72	$ 85.56	$ 21.00	$ 68.16	$ 140.64	$ 129.24		15
Approximate Number of Fixtures in System	5,200	2,500	400	15	1,400	45		16
Total Annual Savings Upon Full Conversion (line 15 x line 16)	$ 222,144	$ 213,900	$ 8,400	$ 1,022	$ 196,896	$ 5,816	$ 648,178	17

Notes
3. Utilizing approved rates in effect currently

Q-6 It is noted under Section 4, D-4 <u>Line Extensions</u> that the proposed budget of $1,677,000 is subject to being partially offset by customer contributions. Is this the only budget item that may be offset by customer contributions?

<u>Response:</u>

Q-6 The terms and conditions for collecting customer contributions are set out in the Company's Rates, Schedules and Policies Manual as filed with IRAC and amended from time to time. The Standard Facility allowance for services and extensions is 90 metres of standard overhead design for Residential, General Service and Small Industrial rate categories and includes required transformation and metering for single or three phase service. Customer needs that exceed 90 metres are billed on a cost recovery basis. Contributions for Large Industrial customers depend on whether service is provided at the transmission or distribution level. Contributions are required to be paid in advance. Customers are entitled to refunds if additional development takes place within five years on those facilities paid for through customer contributions.

Depending upon the type of work performed to serve the customer, the contribution will offset expenditures in either D-3: Services and Street Lighting or D-4: Line Extensions as noted in the Application evidence.

Q-7 One of the main determinants for identifying line rebuilds in Section 4 – D-5 is the existence of Eastern (white) Cedar poles. What is the approximate percentage of Eastern Cedar poles that remain within the distribution network?

Response:

Q-7 Approximately 15%, or 19,000, of the poles in the distribution system are eastern cedar. The untreated eastern cedar poles in the distribution system have an estimated age in the range of 35 – 45 years and represent the vast majority of pole replacements as most have reached the end of their useful lives. Currently, eastern cedar poles represent the majority of the Company's pole failures. The budget allocation in D-5 is used to proactively replace aged untreated eastern cedar poles approaching the end of their useful lives before they fail along with several other drivers for replacements, including upgrades to address voltage sag and reliability concerns, and to accommodate electrical load growth.

Q-8 There is a budget amount of $567,000 for the Porcelain Cutout Replacement Program within Section 4. What is the cause of failure to porcelain cutouts? What is the prescribed replacement material?

Response:

Q-8 The life expectancy of a porcelain cutout is dependent upon the environmental factors under which they operate, such as salt and dirt contamination and freeze/thaw fluctuations in temperature. PEI's environment is conducive to both of these factors which contribute to the premature failure of porcelain cutouts. Cutouts prematurely fail by developing hairline cracks which weaken both the electrical and mechanical integrity of the porcelain cutout and can potentially cause pole fires. This problem is not unique to PEI and Maritime Electric. All of the electrical utilities in Atlantic Canada are experiencing premature failure of porcelain cutouts and have stopped installing them in favor of polymer synthetic cutouts. The polymer synthetic cutout is designed to withstand the environmental factors that lead to hairline cracks. To date, the Company has recorded only ten failures of polymer synthetic cutouts since 2008.

Q-9 In regards to D-6 within Section 4, Watt-hour Meters, it would appear that the budget only addresses the new Remote Interrogation (RI) meters associated with load growth and replacing existing RI meters. Please confirm that all the electro-mechanical meters have been replaced within the distribution system.

Response:

Q-9 Management expects to have these meters converted by the end of 2015. As of October 1, 2014 there are 73,675 active meters in service with 561 electromechanical meters remaining to be replaced with RI technology. This small group is primarily comprised of commercial customers with combination meters that measure demand and consumption.

Q-10 Under D-8 of Section 4, <u>Transportation Equipment</u>, a total budget of $963,000 is assigned for the replacement, installation of new chassis and unforeseen capital expenditures. Is there any allowance for salvage value of the replaced vehicles? If not, why not?

<u>Response:</u>

Q-10 The proposed capital expenditures in Section D-8 Transportation Equipment represent the gross cost of purchasing the replacement vehicle or equipment. In accordance with the Company's accounting procedures, the value of new capital items is recorded at gross cost and the value of any item retired, together with the cost of dismantling or removing from service, less any credits for salvage is charged to the Depreciation or Retirement Reserve accounts.

The table from Section D-8 is presented below with estimated salvage proceeds for each unit to be replaced.

	Vehicle Replaced	Description	Location	Age (Yrs)	Replacement Cost ($)	Estimated Salvage ($)
1.	07-05-25	Canyon ½ Ton	Construction Services	9	35,000	1,000
2.	07-08-26	½ Ton Van	Technical Services	9	35,000	1,000
3.	08-05-73	Tacoma 4x4	Eastern Line Department	8	35,000	1,500
4.	08-06-82	F150 4x4 Ext Cab	Western Line Department	8	35,000	1,500
5.	07-08-20	½ Ton Van	Technical Services	9	35,000	1,000
6.	03-12-53	Single Axle Digger chassis and boom	Central Line Department	12	280,000	10,000
7.	04-12-59	Tandem Digger chassis and boom	Eastern Line Department	13	350,000	20,000
8.	12-04-86	Jeep Cherokee	180 Kent Street	3	50,000	1,500
9.	New	Pole Trailer	Central Line Department		20,000	-
10.	Allowance for unforeseen capital expenditures				88,000	-
Total					<u>$963,000</u>	<u>$37,500</u>

Q-11 The budget for the <u>Y-104 Transmission Line</u> is described in Section 5, with the timetable and costs for this multi-year project included. Please comment as to whether this project is on schedule and within budget at this juncture. Please also comment as to whether there are any potential contingencies that would impact the proposed schedule and overall budget.

<u>Response:</u>

Q-11 The Y-104 transmission line project is progressing well and for 2014 is projected to be on budget and completed within the schedule outlined in the 2015 Capital Budget Evidence. There are several challenges that the Company may face over the next few years that could impact the timelines of the project. Although the approval to proceed has been received from the PEI Department of Environment, Labour and Justice, there are several areas of the project that are considered environmentally sensitive and may require further consultation with key stakeholders prior to construction. The Environmental Protection Plan outlines best management practices and procedures and specific instructions and mitigation associated with the construction of high voltage transmission lines in PEI. In the event that any new environmentally sensitive features, including species at risk and of conservation concern, are encountered in the field prior to or during construction, the appropriate regulatory authorities will need to be consulted and additional mitigation measures may need to be developed and implemented. Project timelines may be affected by mitigation measures. In addition, equipment deliveries may affect project timelines.

Q-12 Within Section 6, Corporate, there is a budget item of $56,000 to <u>Vegetation Management</u> in regards to developing software for managing line cutting operations. It is fully recognized that trees falling on power lines is a major source of power outages and the resulting costs to restore electrical service. What is the current method of scheduling tree cutting activities? Was there a cost-benefit analysis to determine if the software option is more cost effective than the present method?

<u>Response:</u>

Q-12 The data collected from the 2010 field assessment and the ongoing field inspections of transmission and distribution lines are used to identify areas of the Company's distribution and transmission delivery system with heavy, medium or light vegetation growth. The Company prioritizes tree trimming activities based on vegetation growth and historical reliability of the line. Areas with heavy vegetation growth and low reliability due to tree-related outages are at a high priority.

The traditional methods of compiling and maintaining vegetation information is considered insufficient to support this critical activity due to the volume of data and unpredictability of vegetation growth. An IT-based Vegetation Management program that integrates forestry information (now collected by Government and includes information such as species type and height of the trees) with the Company's Customer Information System, Geographical Information System and Outage Restoration System will be used to project a vegetation management cycle. A cost benefit analysis was not performed against the current method as the status quo was not considered as maximizing the value of expenditures. The primary benefits of the Vegetation Management system is that it will provide the Company with a more effective and efficient means of prioritizing tree trimming, and will maintain an accurate information database of tree trimming activities which will enable analysis for supporting expenditure decisions.