MARITIME ELECTRIC
A FORTIS COMPANY

September 25, 2015

RECEIVED
SEP 25 2015
The Island Regulatory and Appeals Commission

MLA

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

Dear Mr. Lanigan:

2016 Capital Budget Filing Docket UE20724
2014 Depreciation Study Filing Docket UE21603
Response to Interrogatories from Mr. Roger King

Please find attached the Company's response to the Interrogatories filed by Mr. Roger King with respect to the 2016 Capital Budget and 2014 Depreciation Study filings. An electronic copy will follow shortly.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Director, Regulatory & Financial Planning

JCR59
Enclosure

MARITIME ELECTRIC
A FORTIS COMPANY

Via email: randjking@pei.sympatico.ca

September 25, 2015

Mr. Roger King
519 Simpson Mill Rd
Hunter River PE C0A 1N0

Dear Mr. King:

2016 Capital Budget Filing Docket UE20724
2014 Depreciation Study Filing Docket UE21603
Response to Interrogatories

Please find attached the Company's response to your Interrogatories with respect to the 2016 Capital Budget and 2014 Depreciation Study filings.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Director, Regulatory & Financial Planning

JCR60
Enclosure

1. King

Given that MECL proposes "the Company will undertake a Decommissioning Study with respect to the CTGS that will provide an estimate of the cost of decommissioning and retiring the facility, and incorporates Management's plans to potentially stage the retirement of individual generation units within CTGS, and that this study be filed with the Commission no later than June 30, 2018", would it not be prudent to extract the $6.2M estimate for site removal for the CTGS from the proposed depreciation rates until the study is filed thereby improving the balance of rate impact to customers until a more accurate estimate is calculated?

1. Response:

Gannett Fleming states the following in its Report (page IV-3):

> *The net salvage for the Charlottetown Steam plant is expected to occur mostly in connection with the final retirement of the plant. In order to estimate terminal net salvage accurately, a site-specific decommissioning study is required. Gannett Fleming recommends that the company undertake such a study in the future. It is generally recognized that the cost of decommissioning and dismantling a steam plant will significantly exceed the salvage received for any reusable equipment or material at the plant. The proposed net salvage estimate of negative 10% is based on net salvage estimates used by other electric companies for similar plants and is recommended until a site-specific decommissioning study can be performed.*

The Company, in adopting the recommendations of Gannett Fleming, are proposing to the Commission that the depreciation rates for CTGS incorporate a 10% negative net salvage (or future removal).

If depreciation rates were adjusted now, as suggested in the question, to eliminate the component of depreciation that addresses the cost of removal for CTGS until the decommissioning study is completed, then customers that are receiving electric service now would not be paying the full estimated costs associated with CTGS during a period in which CTGS will continue to be a component of the Company's generation fleet providing service to customers. As well, following this suggestion would mean that once the cost of removal for CTGS is more accurately determined upon the completion of the decommissioning study, the adjustment to the depreciation rates at that time may need to increase to higher levels than those currently recommended to capture the estimated future removal costs set out in the decommissioning study. And there would be fewer remaining years to capture these costs through depreciation rates before the plant is retired.

In the absence of a decommissioning study the Company feels it is prudent to follow Gannett Flemings recommendation of using a 10% negative net salvage estimate which is used by other electric companies for similar plants.

2. <u>King</u>
Could you confirm that the suggestion in Question 1) would adjust the estimated customer rate increases from 2.1% in 2016 and a further proposed increase around 1% starting in 2019, to 1.5% in 2016 and potentially no further increases as a result of a more accurate site removal cost and the offset savings of a CTGS O&M reduction of $3M per year starting in 2019?

2. **Response:**

The Company is proposing adjustments to depreciation rates effective January 1, 2016, that would result in (based on 2014 values) an estimated increase in the Company's revenue requirement of approximately 2.1%. The Company has not proposed any increase in rates starting in 2019. The Company has proposed to complete and file with the Commission a subsequent depreciation study no later than June 30, 2018 at which time the Company will make further recommendations on adjustments to depreciation rates and specifically will address further adjustments associated with the accumulated reserve variance, the results of the decommissioning study and changes, if any, to the retirement timelines associated with CTGS.

The suggestion in Question #1 is that the Company extract the component of depreciation expense for the estimated cost of removal regarding CTGS from the proposed depreciation rates effective January 1, 2016 until a decommissioning study is completed. If the Company is ordered to file a decommissioning study by June 30, 2018, as the Company has proposed, then depreciation rates set at January 1, 2019 would incorporate the results of that decommissioning study (assuming traditional timelines for filing a General Rate Application by the Company).

For clarity, the recommended changes in depreciation does not mean that $6.2 million is proposed to be collected between 2016 and 2021 to accommodate CTGS decommissioning but rather that depreciation rates are adjusted to ensure, given the relatively short period remaining before CTGS's anticipated retirement, that depreciation rates are sufficiently adjusted to ensure the asset is fully depreciated and that a $6.2 million cost of removal reserve is in place by 2021. The provision for future site removal and restoration for CTGS, at December 31, 2014 was approximately $3.1 million which leaves approximately $3.1 million to be recovered through depreciation rates by 2021 to achieve a $6.2 million cost of removal reserve for CTGS.

Removing, the 10% negative net salvage component from the depreciation rates as presented by Gannett Fleming in Table 3 (page VI-10) of the 2014 Depreciation Study would reduce the annual accrual for depreciation from $2.768 million to $2.517 million annually (and with respect to the CTGS reserve variance from $2.117 million to $1.925 million annually). This would result in a decrease in depreciation expense and revenue requirement of approximately $0.443 million annually. Between 2016 and 2018, based on an annual estimated pre-adjusted revenue requirement of $200 million, rates would be approximately .22% lower in each of these 3 years than they would be with the incorporation of the 10% negative net salvage component.

3. **<u>King</u>**
Part of the cost of decommissioning the CTGS will presumably include fuel inventory. Could you provide the current cost/value of inventoried fuel and all committed purchase contracts together with an estimate of the operating hours and elapsed years for the CTGS that this current and contracted fuel will provide?

3. **Response:**

The current value of Bunker C inventory as of August 31, 2015 is $2,633,203.

The current Bunker C supply contract has ended and the Company is now in negotiations with several suppliers for the Company's future needs. The Company's annual fuel supply requirements are typically based upon historical usage and have been provided to prospective suppliers. The Company does not make firm commitments regarding the volume purchased.

As the CTGS is a part of the reliability plan for the Company, fuel levels must be maintained near 100% capacity (7 days of generation) until such time that the CTGS is put into long term layup. Once the need for fuel is no longer required the Company will seek buyers for any remaining Bunker C fuel.

4. **King**
Given that 60% of the shortfall in past annual capital depreciation amounts adopted by MECL occurred for the generation plants, which in turn has now increased the cost of Island-based fossil fuel generation even higher, please provide for each of the generating sets - CTGS, Borden and CT3:

a. A summary of the annual energy produced and the total operating, depreciation and fuel costs combined as KWh unit cost since 2010 and the forecasted changes to 2021.

b. A current comparison between purchasing non-spinning reserve from NB Power and the now more expensive future cost of Island generation for each year from 2016 to 2021. For 2017/2018 and beyond this question assumes a scenario of the new 360MW mainland/PEI cables in place, resolved mainland transmission restrictions and therefore no requirement for peak load capacity.

4. **Response:**
5. The following table shows the all in cost (operating, depreciation and fuel costs) per MWh by year and for each generating facility.

All in cost (Operating, Depreciation and Fuel)/MWh			
Year	**CTGS $/MWh**	**CT3 $/MWh**	**Borden $/MWh**
2010	3,089.90	7,257.26	4,043.12
2011	1,369.87	4,277.59	2,135.29
2012	460.25	335.29	777.41
2013	1,949.97	725.88	958.91
2014	964.37	713.32	1,529.26
2015	936.67	327.56	1,248.15
2016	2,109.11	351.17	1,263.44
2017	2,261.68	439.52	1,414.58
2018	n/a	479.59	1,396.42
2019	n/a	498.19	1,457.66
2020	n/a	507.48	1,486.23

It is important to note that the above all in cost per MWh is not a metric typically used for stand-by or peaking generation facilities. The metric used for stand-by or peaking generation facilities is the incremental or fuel cost per MWh. The table below shows the fuel costs per MWh by year and for each generating facility.

Incremental Fuel Cost in $/MWh			
Year	**CTGS $/MWh**	**CT3 $/MWh**	**Borden $/MWh**
2010	188.48	262.38	428.27
2011	188.89	247.07	320.25
2012	231.39	221.67	315.01
2013	305.67	256.96	373.65
2014	231.30	317.51	433.98
2015 F	208.17	170.61	288.04
2016 F	199.70	213.35	394.42
2017 F	346.18	297.53	525.81
2018 F	n/a	302.96	532.75
2019 F	n/a	317.43	546.43
2020 F	n/a	325.97	559.77

a. Since MECL can supply its 10 minute and 30 minute non-spinning reserve requirements from the existing combustion turbines (the two Borden units and CT3), MECL avoids the purchase of non-spinning reserve from NB Power (see table below). As the combustion turbines are peaking and standby units and not base loaded units, the benefit of non-spinning reserve does not carry a price but results in the avoided cost as shown below.

Year	Forecast Avoided cost by Self Supplying
2016	$1,970,317
2017	$2,009,723
2018	$2,049,918
2019	$2,090,916
2020	$2,132,735
2021	$2,175,389

5. <u>King</u>

Given that MECL proposes to "incorporate the estimated average service life of assets and a prudent allowance for the cost of removal of assets upon retirement" can you explain how a reserve for the cost of removal of the assets upon retirement for each asset class will appear on the MECL balance sheet starting in 2016 and the annual amount envisaged for each asset class?

5. **<u>Response</u>:**

An established deprecation rate assigned to a group of assets is made up of the following components:

- Plant recovery rate
- Net Salvage (or cost of removal) rate, and
- Reserve variance amortization rate (if applicable)

At December 31, 2014, the Company has approximately $37.2 million within the accrual for Accumulated Amortization of Property, Plant and Equipment that relates to the provision for Net Salvage or Future Site Removal and Restoration.

There will be no change to the appearance on the MECL balance sheet starting in 2016; however, the amount of this provision will be adjusted annually to reflect the Commission's Order with respect to the disposition of changes to depreciation rates as outlined in the Company's Application regarding the 2014 Depreciation Study. The 2016 information requested cannot be confidently provided as it is subject to actual expenditures and retirements in 2015, a determination by the Commission for approved capital expenditures in 2016 and the disposition by the Commission as to depreciation rates effective January 1, 2016. As well, the Company maintains its forecast information at a rolled up level and not at an asset grouping level. The Company has provided, in response to Question 6(a), a breakdown of the Future Site Removal and Restoration Provision, by asset grouping level, as at December 31, 2014.

6. <u>King</u>

Using the MECL December 2014 balance sheet, could you provide a content breakdown of the current Liability entry referring to "Future site removal and restoration provision" showing:

a. each separate allocation for each MECL site and any Point Lepreau obligations

b. How each of these allocations have changed each year since 2010 and the forecasted changes to 2021

6. **<u>Response</u>:**

6.a each separate allocation for each MECL site and any Point Lepreau obligations

The following table outlines the allocation for each MECL asset grouping:

Removal Costs Included in Accumulated Amortization		
Group	**Name**	**2014**
Generation	Prod Power Plant Build & Structures	$ 329,002
Generation	Prod Pumphouse Elect Equip	94,460
Generation	Prod Pumphouse Mech Equip	1,909
Generation	Prod Boiler Plant Equip	1,294,120
Generation	Prod Turbine & Aux Equip	1,071,264
Generation	Gas Turbine & Aux Equip	152,537
Generation	Prod Elect Equip Plant & Yard	154,991
Generation	Prod Misc Power Plant Equip	85,724
Generation	Prod Shop Equip	375
Generation	Prod River Pumphouse Build	35,499
Generation	Prod Borden Build & Structures	4,888
Generation	Prod Borden Gas Turbine & Aux Equip	64,509
Generation	Prod Borden Misc Equip	2,633
Distribution	Dist Substation Equip Build & Structures	39,665
Distribution	Dist OH Conductors	5,951,704
Distribution	Dist Poles & Fixtures	9,426,391
Distribution	Dist Line Control Devices	575,966
Distribution	Dist Tranformers	628,446
Distribution	Dist Transformer Installations	80,554
Distribution	Dist Service Lines	12,520,182
Distribution	Dist Street & Yard Lights	279,644

Group	Name	2014
Distribution	Dist UG Conductors	52,587
Distribution	Dist UG Service Lines	79,445
Distribution	Dist UG System Street Lights	45,950
Distribution	Dist Meters	5,340
Distribution	Dist Communications System	417,093
Transmission	Trans Towers	87,719
Transmission	Trans OH Conductors	2,038,240
Transmission	Trans Poles & Fixtures	1,583,902
Transmission	Trans Line Control Devices	89,355
		$ 37,194,093

With respect to the Company's obligations regarding future site removal or decommissioning for the Point Lepreau facility, the Company contracts output from Lepreau through a Unit Participation Agreement and accordingly is billed monthly by the facility owner NB Power. The monthly billing includes Maritime Electric's share of NB Power's provision for the eventual decommissioning of the Point Lepreau facility.

Using the MECL December 2014 balance sheet, could you provide a content breakdown of the current Liability entry referring to "Future site removal and restoration provision" showing:

6.b How each of these allocations have changed each year since 2010 and the forecasted changes to 2021

The following table reflects the changes in each asset grouping from 2010 to 2014. The amount of the liability at each year end varies as a result of the changes in the related accumulated depreciation for the group. The changes are a result of additions and retirements within the group. When property, plant and equipment is disposed of or retired, the original cost is charged to accumulated depreciation.

Removal Costs Included in Accumulated Amortization					
Group	Name	2011	2012	2013	2014
Generation	Prod Power Plant Build & Structures	$(23,372)	$10,463	$1,939	$ 9,999
Generation	Prod Pumphouse Elect Equip	3,706	3,994	3,706	3,706
Generation	Prod Pumphouse Mech Equip	75	81	75	75
Generation	Prod Boiler Plant Equip	20,702	43,181	42,813	48,837
Generation	Prod Turbine & Aux Equip	(6,067)	43,788	47,162	43,862
Generation	Gas Turbine & Aux Equip	20,760	23,776	22,519	24,109
Generation	Prod Elect Equip Plant & Yard	5,189	5,670	5,189	5,189
Generation	Prod Misc Power Plant Equip	3,365	3,656	3,424	3,424
Generation	Prod Shop Equip	15	16	15	15
Generation	Prod River Pumphouse Build	(266)	2,431	2,333	2,333
Generation	Prod Borden Build & Structures	343	358	348	350
Generation	Prod Borden Gas Turbine & Aux Equip	(2,924)	7,477	5,357	(7,554)
Generation	Prod Borden Misc Equip	233	240	233	233
Distribution	Dist Substation Equip Build & Structures	3,807	4,232	(6,759)	4,370
Distribution	Dist OH Conductors	269,355	417,065	512,255	490,021
Distribution	Dist Poles & Fixtures	216,274	529,645	589,815	549,581
Distribution	Dist Line Control Devices	49,786	66,608	(40,176)	(36,661)
Distribution	Dist Tranformers	3,419	(9,196)	46,714	20,921
Distribution	Dist Transformer Installations	(6,160)	(2,401)	7,753	7,276
Distribution	Dist Service Lines	559,179	757,950	761,253	826,103
Distribution	Dist Street & Yard Lights	14,703	16,243	16,337	4,447
Distribution	Dist UG Conductors	3,685	3,897	3,985	3,987
Distribution	Dist UG Service Lines	5,260	5,530	5,388	5,170
Distribution	Dist UG System Street Lights	1,783	1,923	1,783	1,783
Distribution	Dist Meters	(38,118)	(20,997)	(7,488)	(4,125)
Distribution	Dist Communications System	40,303	42,464	42,337	43,774
Transmission	Trans Towers	398	2,912	2,637	2,637
Transmission	Trans OH Conductors	58,832	130,393	131,452	129,888
Transmission	Trans Poles & Fixtures	(99,563)	4,828	(13,468)	(7,444)
Transmission	Trans Line Control Devices	2,477	5,962	6,106	3,766
		$1,109,190	**$2,104,201**	**$2,197,047**	**$2,182,084**

Please see the explanation provided in the response to Question #5 as to why forecast information cannot be provided.

7. **King**
For the years 2010 to 2021 (actuals and estimates) please provide a table showing the $ values of fixed assets, accumulated depreciation, capital expenditure, fixed asset depreciation/amortization expense and retained earnings and explain how the accumulated depreciation, capital expenditure and fixed asset depreciation/amortization expense are related.

7. **Response:**

The following table sets forth the actual amounts for fixed assets, accumulated depreciation, capital expenditures, fixed asset depreciation/amortization expense and retained earnings for the years 2010 to 2014, and forecast 2015.

	Fixed Assets	Accumulated Depreciation	Capital Expenditures (net)	Fixed Asset Depreciation / Amortization Expense	Retained earnings
	$	$	$	$	$
2010	472,440,739	148,629,447	22,420,014	12,696,136	94,813,502
2011	493,320,012	156,811,230	23,184,843	13,337,249	99,357,864
2012	511,716,642	165,027,490	22,376,729	13,965,125	104,999,169
2013	529,226,674	173,479,218	22,128,373	14,439,089	98,215,983
2014	554,018,360	184,784,475	26,710,078	15,120,635	102,759,727
2015F	580,445,469	198,092,830	28,229,290	15,934,423	108,174,382

Forecast information beyond 2015 cannot confidently be provided as the information requested is subject to ongoing determinations by the Commission during the 2016-2020 period for several variables including depreciation rates, capital expenditures, regulated return on equity, demand side management, and general rate adjustments.

Property, plant and equipment (Fixed Assets) are recorded at original cost which includes an Allowance for funds during construction (AFUDC) and General Expense Capital (GEC). Expenditures for additions, replacements and improvements which comprise direct labour, material, engineering and related overhead costs are capitalized whereas repairs and maintenance costs are charged to operations. When property, plant and equipment are disposed or retired, the original cost is charged to accumulated amortization. As a result, there is no gain or loss recorded in income.

Amortization is determined by the straight-line method based on the estimated remaining service lives of the amortizable assets (net of customer contributions). Annual additions and retirements are deemed to occur at mid-year and the annual depreciation rate is applied at half the amount. The estimated average service lives and average amortization rates for each major category of plant in service as at December 31, 2014 are summarized as follows:

	Estimated Average Service Life Ranges (years)	Average Amortization Rate
Generation	40	2.5 %
Transmission	37-45	2.3 %
Distribution	31-35	3.2 %
Other buildings and equipment	5-15	6.7 %

Depreciation is an allocation process over the estimated useful life of an asset and as such, is a non-cash period expense that is used in the determination of annual earnings. Retained earnings is adjusted annually by the addition or subtraction of earnings or loss for the period less dividends. Thus, depreciation represents a component of the expense and revenue equation that ultimately determines retained earnings.

2016 Capital Budget Application – UE20724

8. King
Given a 2016 capital expenditure request of just under $31M could the MECL management team construct an alternative, optimum budget for 20% less – a target of $24M – and describe the operational changes, risks and mitigation actions that would apply?

8. Response:

The identification and prioritization of capital projects is an on-going process that culminates annually in the Capital Budget Application. Capital project proposals are developed based upon the work requirements identified by the various operating and technical professionals within the Company. Management will take these proposals and prioritize the projects based upon the factors discussed below balanced against consideration of the impact the expenditures will have on customer rates.

The annual capital budget submission to IRAC is based upon a number of factors including:

- Customer requests driven by organic growth, load growth or required capital improvements,
- System reliability improvements,
- Safety and insurance requirements, and
- Replacements due to adverse weather, fire, collisions.

As an electric utility regulated by IRAC under the provisions of the Electric Power Act ("EPA"), Maritime Electric has an obligation to serve its customers and maintain appropriate levels of service reliability. Discharging our obligations under the EPA requires ongoing investment in our energy delivery infrastructure, including our transmission and distribution, generating and customer related facilities.

Presenting an alternative budget at 80 percent of the current budget request would not provide a realistic representation of the level of expenditure required to meet system reliability expectations or the annual customer driven service requirements.

An alternative capital budget of $24 million (i.e. 20% less) would substantially restrict the Company to primarily making expenditures only in the areas of generation and customer/load growth driven expenditures in distribution and transmission. Ongoing, and necessary, expenditures to address deteriorated and end-of-life asset replacement would have to be deferred. Doing so would result in larger expenditures in future to address the deferral as the need to address deteriorated and end of life assets is unyielding. As an example of deferring expenditures of this nature with respect to the proposed 2016 Capital Budget: single and three phase rebuilds ($2.16 million), pole for pole replacement ($0.4 million), transportation equipment ($0.752 million), transmission line refurbishment ($0.850 million), Y-104 multi-year project ($2.884 million) and insulator replacement on T-10 ($.254 million) would total $7.3 million for the year (or about 24% of the proposed capital budget).