MARITIME ELECTRIC
A FORTIS COMPANY

RECEIVED
9:45 AM
OCT 19 2016
hand del
The Island Regulatory and Appeals Commission

October 19, 2016

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

Dear Mr. Lanigan:

2017 Capital Budget Filing Docket UE20725
Response to Interrogatories from Commission Staff

Please find attached the Company's response to the Interrogatories filed by Commission Staff with respect to the 2017 Capital Budget filing. An electronic copy will follow.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Director, Regulatory & Financial Planning

JCR42
Enclosure

1. The Combustion Turbine 3 (CT3) has been in operation for approximately 10 years. Why is the 2017 capital budget the appropriate time to consider replacing the back-up water pump from natural gas to liquid fuel?

Response:

1. The planning and specification for CT3 was done in 2004 and the equipment supply contract with General Electric was signed in Fall 2004. During the previous few years, Maritime Electric and the Government of PEI had investigated the possibility of bringing natural gas to PEI. These efforts culminated in the signing of a term sheet with Encana in 2002 for supply of natural gas from Encana's Deep Panuke project which was then under development. However, in 2003 Encana put the development of Deep Panuke on hold and work on bringing natural gas to PEI was suspended.

In 2004, both Maritime Electric and Government still considered securing a natural gas supply for PEI to be an important objective and for this reason the following two provisions were made for possible future operation of CT3 on natural gas:

1. Natural gas nozzles were installed on the combustion system
2. The second NOx water pump was specified to operate with natural gas fuel

In recent years, production at the Sable Island and Deep Panuke offshore natural gas platforms has been less than expected and both of these sites are now expected to be shut down by 2020. The only other natural gas wells in the Maritimes are those near Sussex, NB which are owned by Corridor Resources. However, there are fracking moratoriums in place in New Brunswick and Nova Scotia. For these reasons, Maritime Electric believes that it is now unlikely that natural gas will be made available in PEI in sufficient quantities to fuel CT3 in the near to medium term. Thus, there is no longer a reason to have the second NOx water pump designed to operate on natural gas fuel.

Like most generating units, CT3 has redundancy built in to its auxiliary systems. For CT3, these include:

- Two 100% low pressure diesel fuel forwarding pumps for delivering fuel from the storage tank to the unit
- Two 100% high pressure diesel fuel pumps for injecting fuel into the combustor
- Two 100% equipment enclosure ventilation fans
- Two 100% lube oil pumps for the generator

By replacing the natural gas NOx water pump with a second NOx water pump designed to operate with diesel fuel, the NOx water system will also have a level of redundancy similar to the auxiliary systems listed above. Without a backup NOx water pump, CT3 would be limited to an output of only 15 MW in the event of a failure of the existing NOx water pump (CT3's rated capacity is 49 MW).

Replacing the existing NOx water pump that is designed to operate with natural gas with a second NOx water pump that is designed to operate with diesel fuel would involve the following:

- Purchase of a new pump, complete with 100 horsepower motor and gearbox (the existing NOx water pump that is designed to operate with natural gas has a 50 horsepower motor).
- Installation of a new motor starter, wiring and controls.
- There may be a need to upgrade some piping because the pump designed to operate with diesel fuel operates at a higher pressure than the pump designed to operate with natural gas.

Maritime Electric currently has 104 MW of generating capacity at the Charlottetown Plant site. This consists of 55 MW from the Charlottetown Thermal Generating Station (CTGS) and 49 MW from CT3. One of the roles for this capacity is to back up the on-Island transmission system. With the planned long-term layup and decommissioning of the CTGS on the planning horizon, this will leave only CT3 at the Charlottetown Plant site (until such time as new capacity is contracted or constructed). This places greater importance on the reliable operation of CT3.

In summary, Maritime Electric has included the purchase and installation of a second NOx water pump designed to operate with diesel fuel in the 2017 Capital Budget for the following reasons:

1. The Company believes that it is now unlikely that natural gas will be made available in PEI in sufficient quantities to fuel CT3 in the near to medium term, and
2. The planned long-term layup and decommissioning of the CTGS places greater importance on the reliable operation of CT3 to back up the on-Island transmission system.

2. The initial cost for Cherry Valley/Mount Mellick substation was budgeted and approved in 2016 budget yet it re-appears in 2017, please explain.

Response:

2. The Company's 2016 Capital Budget Application included a provision for an Environmental Impact Assessment (EIA) and land purchase for a new substation in the Cherry Valley area. With the completion of the EIA in 2016, the proposal for the construction of the new substation, along with the associated transmission and distribution work, was expected to be included in the Company's 2017 Capital Budget Application, which would address an overload at Crossroads substation forecast to occur in the winter of 2018.

This load forecast was reviewed in 2016 and, due to a reduction in the forecast rate of growth, it was determined that the construction of a new substation to address loading at Crossroads substation would not be required until 2018 to address a forecast overload in the Winter of 2019. Consequently, the Environmental Impact Assessment and land purchase would be required in 2017 instead of 2016. The Company also completed an updated engineering assessment and determined that the most appropriate location for the substation would be in the Mount Mellick area instead of Cherry Valley.

As a result of the change in substation location as well as the year in which it is required, it was decided that the work budgeted and approved for 2016 would be cancelled and the Company would seek approval to complete the work in 2017.

3. The monies set aside in 2016 capital budget for 69 kV breaker replacement program indicated there were 11 – 40 year old breakers and 4 would be replaced. In 2017 capital budget request it seeks to replace 4 – 40 year old breakers again and indicates there are 10 breakers which are 40 years and older. Please explain. Please provide further details on number and ages of 69 kV and 138 kV breakers and switches along with planned program for replacement.

Response:

3. The 2016 Capital Budget Application was filed in July 2015. At that time there were 11 breakers identified for replacement as part of the 69 kV breaker replacement program. 4 of those breakers were replaced later that year as planned in the 2015 capital budget resulting in 7 breakers remaining from the original amount.

The 10 breakers identified in the 2017 capital budget include 7 of the original breakers as well as 3 additional breakers that have been identified as requiring replacement. The 3 additional breakers have a manufacture year of 1976, 1979 and 1979, and will be at or near 40 years old in the year which they are actually replaced.

The number and age categories of the 69 kV and 138 kV breakers are shown in the table below. For 69 kV breakers, the Company will continue with the current program until its expected completion by 2018. For 138 kV breakers, prior to 2016 the Company did not have any 138 kV breakers that were 40 years old (the 5 40 year old 138 kV breakers identified in the table below all have a manufacture year of 1976). As these breakers continue to age, the Company will consider a replacement program as required.

Age Category	# of 69 kV Breakers	# of 138 kV Breakers
0-9 Years	14	6
10-19 Years	1	0
20-29 Years	0	2
30-39 Years	7	3
40-49 Years	5	5
50-59 Years	0	0
60+ Years	3	0
Total	**30**	**16**

The number and age categories of the 69 kV and 138 kV switches are shown in the table below. The Company has an Air Switch Inspection Program and a Transmission Line Inspection and Refurbishment Program that provides for annual inspection of transmission lines and switches. Based on the results of these inspections, there is a provision included in the annual capital budget to upgrade and extend the life of selected 69 kV and 138 kV switches or to replace switches when necessary.

Age Category	# of 69 kV Switches	# of 138 kV Switches
0-10 Years	35	33
11-20 Years	10	6
21-30 Years	21	16
31-40 Years	15	25
41-50 Years	23	3
51-60 Years	4	0
61+ Years	0	0
Unknown	10	1
Total	**118**	**84**

4. Please provide further details on the need for replacement of Wellington substation. The Wellington substation is an aged facility. Are there alternatives to placement of substation which would meet long term transmission system needs?

Response:

4. The Wellington Substation was built in 1962 and has reached the end of its useful life. The substation was designed to the standards of the day which included a smaller footprint as large trucks at that time were not required to access the substation for maintenance purposes and CSA clearances were not as stringent as they are today. For example, the CSA code states that the required ground clearances for 12.5 kV is 4 meters. In some cases, these clearances are not achieved at the Wellington Substation, which becomes a safety concern. The footprint of the substation is such that line trucks cannot access the substation which makes it difficult to perform maintenance. The current area of the substation is 400 m^2, while similar substations built to today's standards are 1100 m^2.

Long term transmission system needs were considered in the placement of the substation, and it is expected that the new Wellington substation will be placed at or near its current location. The substation is currently located along Highway #2 near the existing 69 kV transmission line route that supplies the western region of the province, and it is in a central location relative to the customers that it supplies, reducing system losses. The new substation will have provisions for a second power transformer to accommodate future load growth in the area, as well additional distribution circuits.

5. Please provide details for both the Spill Prevention Program and Transclosure Removal Program. Information like time period for program, scope of total cost of program over the term of program, etc.

Response:

5. **Spill Prevention Program**

Maritime Electric has approximately 33,000 oil-filled distribution transformers installed in its service territory. The purpose of the Spill Prevention Program is to minimize the release of transformer oil into the environment that can result from damage or corrosion. Criteria used to identify transformers to be replaced include the transformers age, loading, location, and physical condition. The 200 transformers identified for replacement in 2017 were selected from a group of approximately 750 pre-1982 transformers that contain oil which has not been tested for PCB concentration. This group of transformers currently has an average age of 37 years.

The Spill Prevention Program is expected to continue as an annual capital program and has no defined time period for completion. As the number of untested pre-1982 transformers is reduced, other criteria will be used to identify transformers for replacement in order to reduce the risk of spills into the environment. The Company is currently considering a distribution inspection program that will identify transformers for replacement based on physical condition, corrosion, etc. The current cost of the Spill Prevention Program is approximately $375,000 per year.

Transclosure Removal Program

The Transclosure Removal Program involves the replacement of ten transclosures over three years. Transclosures contain pole mounted transformers that are fed from an underground source. These installations are no longer an approved design and are a safety concern due to the proximity to energized high voltage equipment. Each transclosure will be replaced with a padmount transformer to align with current standards. The total cost of the program (not including the cost of the padmount transformer) is shown in the table below. By the end of 2019 the Company will have no transclosures remaining.

Year	# of Transclosures	Estimated Capital Cost
2017	3	$90,000
2018	4	$120,000
2019	3	$90,000

6. **What is the anticipated rate impact of capital expenditures planned in this application?**

Response:

6. The proposed capital expenditures of $29,399,000 corresponds to the 2017 financial input for capital expenditures included in the Company's General Rate Application which was approved by the Commission in Order UE16-04.

Under the Company's accounting policy for depreciation of capital assets, one half year depreciation is recorded in the year of addition. Each subsequent year will have a full year of depreciation until the asset is retired.

As shown in the schedule below, based on an annual revenue requirement of $200 million, the rate impact is approximately 0.23% in 2017 (half year of depreciation) or 0.45% on an annual basis using the current approved depreciation rates.

Asset Class	**2017 Additions**	**Allocation of GEC/IDC**	**Total 2017 Additions**	**Approved Depreciation Rate**	**2017 Depreciation**
Production Plant					
- Charlottetown Thermal Generating Station	242,000	6,700	248,700	4.53	5,600
- Borden Generating Station	135,000	3,800	138,800	4.81	3,300
- Combustion Turbine #3	876,000	24,400	900,400	2.28	10,300
Transmission Plant	8,641,000	240,500	8,881,500	2.27	100,800
Distribution Plant	18,030,000	501,900	18,531,900	3.32	307,600
General Plant	1,068,000	29,700	1,097,700	5.96	32,700
Subtotal	28,992,000	807,000	29,799,000		460,300
Contributions	(400,000)	-	(400,000)	2.95	(5,900)
Total	**28,592,000**	**807,000**	**29,399,000**		**454,400**
Estimated Revenue Requirement					200,000,000
Estimated Rate Impact 2017					**0.23%**
Estimated Rate Impact - Full Year Depreciation					**0.45%**