MARITIME ELECTRIC
A FORTIS COMPANY

September 2, 2010

Mr. John Kenny
President
PEI Senior Citizens Federation Inc.
40 Enman Crescent, Suite 117
Charlottetown PE  C1E 1E6

Dear Mr. Kenny:

**Maritime Electric Company, Limited**
**2011 Capital Budget**

Maritime Electric's responses to the interrogatories filed by the PEI Senior Citizen's Federation Inc. are contained herein.

Yours truly,

MARITIME ELECTRIC

J. W. Geldert
Vice President, Finance and Administration
And Chief Financial Officer

JWG58
Enclosure

cc: Mark Lanigan (IRAC)

SIEMENS

SB/EAS/01-003

# SERVICE BULLETIN
# RECOMMENDED

01-September-2001

SUBJECT : **CORROSION OF POWER TURBINE ROTOR ASSSEMBLY**

## A. TURBINES AFFECTED

All EAS1 turbine sets.

## B. REASONS FOR BULLETIN

To advise users on the potential risk of corrosion to the rotor assemblies and the recommended course of action.

## C. CATEGORY

Initial inspection can be performed in the field.

## D. DESCRIPTION

As a result of inspections, some turbines have been found to have corrosion on the rotor disc face and firtree root areas. These include both standby and base load units. This bulletin clarifies the inspection procedures and coating recommendation.

## E. IMPLEMENTATION

1 Users are recommended to make regular inspections of the power turbine rotor disc to check for the possibility of corrosion on web surfaces and firtree root profiles.

2 Depending on atmospheric conditions and turbine duty, corrosion may be found on the disc faces or in the fir tree root areas. In severe cases corrosion pitting may be present and, if found, the rotor should be removed for detailed inspection at an approved SIEMENS Power facility. NO ATTEMPT SHOULD BE MADE TO DRESS OUT, OR OTHERWISE REMOVE, CORROSION OR PITTING. The disc is a highly stressed component and any reduction in profile, or the introduction of stress raising marks, will adversely affect the operating safety margins.

3 At the next 25,000 hour inspection or within the next year, whichever is the sooner, inspect the disc surfaces for corrosion. If corroded, remove the blades from the disc to allow a thorough inspection of the fir tree root profile. Particular attention should be paid to units on standby or intermittent duty, which are not inspected at frequent intervals. Corrosion may still occur even when the unit is at rest.

**© Siemens Industrial Turbomachinery Ltd.. 2001**

CONFIDENTIAL

This bulletin is the exclusive property of Siemens Industrial Turbomachinery Ltd. and is disclosed in confidence to Siemens Industrial Turbomachinery Ltd. customers solely for their use in connection with the operation and maintenance of their Siemens Industrial Turbomachinery Ltd. turbines. Its contents shall not be used for other purposes or copied or disclosed without written authorisation of Siemens Industrial Turbomachinery Ltd. The information set out in this bulletin is offered by Siemens Industrial Turbomachinery Ltd. as part of its ongoing product support services for you as one of its customers. However, the final decision for operating your plant in a safe and responsible manner rests entirely with you. This involves many factors outside our knowledge and control, and therefore Siemens Industrial Turbomachinery Ltd. is unable to accept (and hereby disclaims) any liability (whether based on breach of contract, warranty or statutory duty, negligence or otherwise) for damage or loss of any kind which may be incurred as a result of applying this information.

Day and night service is available 365 days a year.

All correspondence to:
Siemens Industrial Turbomachinery Ltd.
Waterside South
Lincoln LN5 7FD England
P.O. Box 1
Tel: +44 (0) 1522 584000
Fax: +44 (0) 1522 584900
http://www.siemens.com/industrial-turbines

Siemens Industrial Turbomachinery Ltd.
Registered Office:
Ruston House
Waterside South
Lincoln LN5 7FD England
Registered in England No. 4729734

4 Rotors built after 1978, and which were coated for added protection, including the fir tree root area, may also be found to be corroded.

5 For earlier uncoated rotors, where corrosion is present, it will be necessary to fit a new disc which will be machined and coated to the latest specification. The opportunity can also be taken to coat the turbine shaft if required. This work, including balancing and overspeed of the new assembly, must be carried out at an approved repair facility.

6 Thereafter, the assembly should be inspected at 25,000 hour intervals, and re-coated at 50000 hour intervals, or sooner if site conditions dictate.

7 If the rotor blades are in good condition, they may be re-used in the new disc, but must be modified by SIEMENS to enable the rotor to be balanced to the procedure for coated rotors.

8 It is recommended that blade condition is checked by subjecting one blade to metallurgical testing in accordance with Service Bulletin SB/EAS/01-002 – Power Turbine Rotor Blade Inspection.

9 Later units fitted with coated rotor assemblies, which are found free of corrosion and pitting on initial inspection, should be inspected at 25,000 hour intervals and re-coated at 50000 hour intervals, or sooner if site conditions dictate.

## F. PLANNING INFORMATION

Any user requiring further advice on this subject, should contact:- Customer Support Centre, Demag Delaval Industrial Turbomachinery Ltd. Kirketon Drive, Pitmeddon Industrial Estate, Dyce Aberdeen, AB2T 0BG.

Alternatively, contact can be made through the Demag Delaval Industrial Turbomachinery Ltd. area representative, repair facility or service centre.

1. With the significant change in capital investment proposed for the Charlottetown Plant, it appears that the explanation contained in the evidence document that "the remaining projects were re-prioritized" simply shifted capital funds from the Charlottetown Plant to the Borden Plant. What is the justification for this shift and increased investment especially noting historical capital spends and the extremely high cost of energy generated by the Borden Plant?

**Response**:

1. The evidence explains that certain Charlottetown Plant capital projects have been deferred/postponed pending the determination of funding for a third transmission cable interconnection between PEI and NB. With these projects shelved, the remaining projects covering a five year planning horizon were re-ranked.

   As a result one project, item G-4-1, moved up in priority: the replacement of equipment on the Company's Borden Combustion Turbine #1. The Company is acting upon its insurance company's recommendation to address the Original Equipment Manufacturer's (OEM) servicing recommendations. In 2001, the OEM issued a service bulletin (attached) recommending the proposed replacements. Given the infrequent usage of this generator Management, in consultation with the OEM, had deferred this action. Management believes that the work should be completed in the near future and has proposed it for 2011 at an estimated cost of $1,284,000.

   Management recognizes that the cost of produced electricity from the unit is high; however, the primary role of the Borden generating equipment is not energy production but the following:

   - For submarine cable loading management. The total capacity of the two submarine cables linking the PEI transmission system to the NB transmission system is 200 MW, however the peak load for PEI now exceeds 220 MW. During periods when the load is above 200 MW, on-Island generation is required to ensure the submarine cables do not become overloaded.

- For contingency planning such as back up of off Island energy purchase in the event of a submarine cable failure similar to the incident that occurred in December 1997. During that 26 day event the Charlottetown Plant provided the majority of replacement supply with Borden used for peaking. This submarine cable outage also occurred during the Company's peak load period.
- As a source of ancillary services. In addition to electric utilities being required to meet customer load requirements, utilities must have enough quick start standby generation (Operating Reserve) to accommodate 100% of the loss of the largest generator on the system and 50% of the loss of the second largest generator on the system. In the Maritime Area (New Brunswick, Northern Maine and PEI) the two largest generators are located in New Brunswick and this standby requirement is shared on a load ratio basis. Borden provides MECL's portion of this Operating Reserve.
- As a source of capacity for energy purchases. All energy purchases must be backstopped with capacity. The Company's combustion turbines contribute to lowering the cost of purchased energy every day as a capacity credit.

The savings in avoided purchases of Operating Reserve and capacity from the Borden generation equipment are approximately $2.2 million on an annual basis.

2. What changes have occurred in the MECL assessment of the 2011 capital requirements for "Services and Street Lighting" since the Rate Change Application earlier this year that has caused a 30% increase in required capital?

**Response:**

2. For clarification, it is assumed in the Company's response that the question posed is in reference to the amount provided in a schedule supplementing information provided by the Company in response to the PEISF Interrogatory #4 of May 2010 (Amendment to Rates and Elimination of Second Block) wherein a 2011 capital expenditure amount of $2,632,000 was provided for Services and Street Lights. This has been compared to the $3,425,000 filed for the same account in the Company's 2011 Capital Budget Evidence (a difference of approximately 30%). There are two factors that contribute to the difference between these two amounts.

First, the amount of $2,632,000 excludes Capitalized General Expense (GEC) while the amount of $3,425,000 is inclusive of $170,000 of GEC for a net amount of $3,225,000. See Company response to PEI Senior Citizens' Federation Inc. Interrogatory number 4.

Secondly, the provision of $3,425,000 (or $3,225,000 net of GEC) filed under Services and Street Lights in the 2011 Capital Budget Evidence was increased to more accurately reflect the historical spending that has occurred in this customer driven account. Actual costs in this account (all amounts net of GEC) are as follows:

| Year | Actual Expenditure ($) |
|---|---|
| 2007 | $3,201,678 |
| 2008 | $3,393,021 |
| 2009 | $3,054,514 |
| Average expenditure (2007-2009) | $3,216,404 |
| Amount filed in 2011 Capital Budget Evidence (net of GEC) | $3,225,000 |

It is important to note that expenditures in this account are driven by customers' requests for service.

3. What changes have occurred in the MECL assessment of the 2011 capital requirements for "Line Projects" since the Rate Change Application earlier this year that has caused a 55% increase in required capital?

**Response:**

3. For clarification, it is assumed in the Company's response that the question posed is in reference to the amount provided in a schedule supplementing information provided by the Company in response to the PEISF Interrogatory #4 of May 2010 (Amendment to Rates and Elimination of Second Block) wherein a 2011 forecast capital expenditure of of $968,000 was provided for Line Projects. This is compared to $1,496,000 filed for the same account in the Company's 2011 Capital Budget Evidence (a difference of approximately 55%). There are two factors that contribute to the difference in these two amounts.

First, the amount of $968,000 excludes GEC while the amount of $1,496,000 is inclusive of $319,000 for GEC for a net amount of $1,177,000. See Company response to PEI Senior Citizens' Federation Inc. Interrogatory number 4.

Secondly, the spending requirements for transmission line projects remain provisional within the Company forecasts (such as that provided to the PEISF in May 2010) until a final review of spending priorities and consideration of any necessary changes (new generation projects, the evaluation of reliability-based issues, environmental timeline delays, etc.) are considered in the preparation of the Capital Budget Evidence. In considering the transmission line projects that should be undertaken in 2011, a significant reliability based issue had arisen that warranted a change in required capital spending and is detailed below.

The Company's planned transmission line project priorities were amended to incorporate $526,000 to rebuild 9 km of the T8 transmission line (a line that services much of Kings County and runs from Lorne Valley to Souris). While much of this line has been rebuilt in the past few years, an aged portion of the line remains (1972 vintage) as the Company has been waiting to coordinate the rebuilding of this line with Government road widening in the area (by coordinating construction with road widening the Company avoids the cost of moving poles twice). It has become apparent that road widening in this area is not planned to occur in the near future and there have been two outages on this line in 2010 in this area. Reliability for customers serviced by T8 needs to be addressed and the inclusion of a budget provision of $526,000 to rebuild 9 km of T8 was made to address this.

Subsequently, the Company has scaled back its planned spending on the Y104 transmission project to offset a portion of the $526,000 cost to complete this 9 km of T8. The Y104 project, which will be undertaken over several years, will eventually provide a rebuilt transmission line (current vintage is 1965) for many Kings County residents that will allow for future growth and enhanced reliability.

4. The IFRS changes relating to "Capitalized General Expense" are noted. Please indicate to which capital items the $2M plus labour expenses have now been directly allocated.

**Response:**

4. The following schedule illustrates the allocation of Capitalized General Expense (normal recurring labour charges associated with capital related projects) to the various capital projects in the Company's 2011 Capital Budget Application.

| | | 2011 | GEC |
|---|---|---|---|
| **Generation** | | | |
| G-1 | Charlottetown Plant Building and Services Projects | $ 299,000 | $ - |
| G-2 | Charlottetown Plant Boiler Projects | 470,000 | - |
| G-3 | Charlottetown Plant Turbine-Generator Projects | 364,000 | - |
| G-4 | Borden Plant Projects | 1,284,000 | - |
| | | $ 2,417,000 | $ - |
| **Distribution** | | | |
| D-1 | Replacements Storms, Road Alterations | 1,091,000 | 248,000 |
| D-2 | Distribution Transformers | 3,393,000 | 22,000 |
| D-3 | Services and Street Lighting | 3,425,000 | 170,000 |
| D-4 | Line Extensions | 1,472,000 | 278,000 |
| D-5 | Line Rebuilds | 3,271,000 | 334,000 |
| D-6 | System Meters | 1,356,000 | 105,000 |
| D-7 | Distribution Equipment | 1,419,000 | 116,000 |
| D-8 | Transportation Equipment | 1,011,000 | - |
| | | $ 16,438,000 | $ 1,273,000 |
| **Transmission** | | | |
| T-1 | Substation Projects | 857,000 | 111,000 |
| T-2 | Transmission Projects | 1,496,000 | 319,000 |
| | | $ 2,353,000 | $ 430,000 |
| **Corporate** | | | |
| C-1 | Corporate General | 163,000 | 30,000 |
| C-2 | Information Technology | 909,000 | 370,000 |
| | | $ 1,072,000 | $ 400,000 |
| | | $ 22,280,000 | $ 2,103,000 |
| **Capitalized General Expense** | | 352,000 | |
| **Interest During Construction** | | 210,000 | |
| **Less: Customer Contributions** | | (265,000) | |
| **Total** | | $ 22,577,000 | |

5. The additional $910,000 for 2011 to continue the introduction of the RI meters, still leaving 20,000 customers due for conversion in post 2012 is noted. Has MECL conducted any investigation in changing this conversion program to enable both RI and Smart Metering for the remaining customers? MECL management has indicated support for the initiative taken by Summerside Utility in the Smart Metering project; is this not an opportunity for MECL to directly contribute to the expansion of wind energy integration by actively participating and conducting a second Smart Metering project?

**Response:**

5. The Company continues to follow developments in the area of "Smart" Meters, or Advanced Metering Infrastructure (AMI), in Canada and internationally. The Company's decision to continue with the conversion of residential meters to Advanced Meter Reading (AMR) units (internally referred to as RI or Remote Interrogation meters) reflects its conclusion that this course of action remains cost effective.

Some Canadian utilities, notably those within Ontario and BC, have already begun the implementation of Smart Meters as a result of Provincial Government Legislation making these meters mandatory. Other Canadian jurisdictions and utilities, including the Atlantic Provinces and Quebec, continue to evaluate both the costs of implementation and the potential benefits to be derived from AMI.

Smart Meters have 2-way communication capability and when combined with suitable information technology infrastructure and communications systems they have the ability to provide:

- The same capabilities of the AMR technology being deployed by Maritime Electric, including remote interrogation, elimination of estimates, increased billing accuracy and tamper theft security enhancements.
- Interval or time of use data allowing utilities to introduce different prices for consumption based on the time of day and the season and to provide customers with more detailed information on consumption patterns (which should be helpful to customers in energy conservation initiatives).

- Other tools that can enhance customer service and operating efficiency such as remote connections/disconnections and outage notification/restoration.
- The most advanced features of AMI include demand response features allowing the potential for customers to reduce consumption at critical times or in response to market prices, features to allow an interface with the electric utility grid load controllers to better facilitate customer demand and efficient utility supply response, and ability to communicate/interface with customer displays and programmable applications and thermostats.

The cost of Smart Meter implementation will vary depending on the type of meter, and the information technology infrastructure and communication systems deployed. Hydro One has indicated in its recent rate application to the Ontario Energy Board that the installed cost per Smart Meter in Ontario is estimated at $700. Maritime Electric has approximately 70,000 meter points so an AMI project at $700/meter would require an investment of $49 million. By way of comparison, Maritime Electric's installed cost per meter for AMR is $82.

In order for Maritime Electric, or any utility, to undertake an AMI investment it needs to satisfy itself and its regulator that the benefits to customers derived from the investment will outweigh the investment cost. The Ontario marketplace is expected to provide other Canadian utilities with better information on load shifting, energy conservation and operational efficiencies on which to evaluate an investment in AMI.

One of the most fundamental benefits that must be derived from the Smart Meter, to offset the cost of AMI investment, through the establishment of a pricing structure for different times of day (lower prices in off peak hours and highest prices in peak hours), is a shift in consumption by customers to off peak hours. This allows the utility to defer the need to generate or purchase further energy and capacity.

It is this area that poses a particular, and significant, challenge for Maritime Electric. PEI is unique in Canada that it does not have access to low variable cost generation sources such as hydro or coal. Many jurisdictions, such as Ontario, have a fleet of generation with different sources that are used to meet customer demand. Typically during the off peak hours the lowest cost generation is deployed. This allows a jurisdiction such as Ontario to set an on peak/off peak pricing model for customers that reflects the large differential in the on peak/off peak cost of generation. To be effective research has indicated that the on peak price should be at least double the off peak price (which it is in Ontario).

PEI has (except for base load supply from Point Lepreau and wind which is an intermittent source) a very large dependence on imported market base costed electricity. Unfortunately, energy supply options for PEI do not offer suitable price signals for consumers to act upon. Currently there is a small price differential (in the order of 15% to 20%) between on peak and off peak periods and therefore a poor foundation for an effective time of use rate structure.

The Summerside approach for their smart meter pilot project will see the installation of approximately 400 meters in and around their central service area on Ottawa Street. At an estimated cost of $2,000,000 this pilot project will provide valuable information as to the uptake/interest of these customers who volunteer to participate. As we understand its purpose (City of Summerside 2010 Budget document) the objective is to strive to provide rate discounts for its customers who can alter their electricity consumption when the wind is blowing and who are willing, on a volunteer basis, to allow the Summerside utility to curtail consumption when winds are calm.

Maritime Electric is planning, subject to the approval of IRAC, to conduct a pilot project in co-operation with NB Power, Nova Scotia Power, Saint John Energy and the University of New Brunswick with the primary focus to economically integrate more wind production into the Maritime electricity grid.

The Company is of the view, at this time, that a change in strategy to replace the AMR meter technology currently being deployed with more expensive "smarter" alternatives on a large scale is not justifiable. The Company is investigating the strategic deployment of "Smarter" technologies on a selective basis that could produce operational efficiency gains, assist with energy conservation and lower electricity costs on PEI.

The original business case for the conversion to AMR meters remains valid. Management believes that the deployment of smart technology on a focused basis, together with the solid savings with the AMR conversion project, is the optimal approach for PEI.

6. To enable a capital spend sensitivity analysis please provide a least-impact listing of the same allocation details proposed in the application (Section 2, pager1) for an annual capital spend reduced to $15M maximum for 2011. We request MECL explore this question in more detail than the response to a similar question tabled during the Rate Change application process.

**Response:**

6. In its response to an Interrogatory filed by the PEI Senior Citizens' Federation Inc. in May of this year the Company discussed the development of its budget for capital expenditures. Further discussion was provided during the hearing in June when Management talked about its process for developing and prioritizing capital expenditures. During that discussion Management talked about how it reviewed the various work requirements that had been identified by the various operating and technical professionals within the Company. After assembling and reviewing the proposals Management prioritized the work and the resulting projects became part of the Capital Budget. To reiterate the points raised during these discussions, the Company's capital expenditures are based on the following:

***Safety –*** Expenditures required to ensure the safety of employees and the general public.

***Insurance Requirements –*** The procurement of insurance coverage for its assets requires the Company to make modifications to the facilities to ensure consistency with various operating code requirements.

***Organic Growth –*** Many of the expenditures are required to meet the needs of customers. New construction, industrial/commercial expansion and government infrastructure initiatives drive required capital expenditures by the Company. The Company is required to serve all customers, meaning that where new expenditures are needed to serve customers the Company is obligated to make these capital expenditures.

***Generating Facilities –*** The nature of the Company's operating environment requires the continued maintenance of on-Island generating facilities as backup in case of the loss of the interconnection with the mainland or damage to the on-Island transmission system as a result of human or weather related events.

***System Reliability –*** Maritime Electric's energy delivery system is subject to many forces including the effects of aging and the effects of weather related events. Through the years, ice storms, wind storms, lightning and other issues have affected the system. The effects of these forces along with the age of the system require that the Company continue to replace aged infrastructure on a timely and regular basis to ensure the ability to deliver energy to customers.

On page 25 of Order UE10-03 the Commission discussed its position with respect to system reliability. Management also places high value on the integrity of the energy delivery system and believes that an artificial cap on expenditures would result in deterioration in the system to the detriment of all customers. At the end of the day the Capital Budget reflects Management's expectations for customer driven work and, based on its years of experience, a program of expenditures that will help to strengthen the integrity of the energy delivery system and promote service reliability.