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BY EMAIL

January 15, 2014

Ontario Energy Board
P.O. Box 2319
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2300 Yonge Street
Toronto ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Espanola Regional Hydro Distribution Corporation ("ERHDC").
2014 IRM Distribution Rate Application
Board Staff Submission
Board File No. EB-2013-0127

In accordance with Procedural Order No.1, please find attached the Board staff Submission in the above proceeding. The applicant has been copied on this filing.

ERHDC's reply Submission, if it intends to file one, is due by January 29, 2014.

Yours truly,

Original Signed By

Birgit Armstrong
Advisor, Applications & Regulatory Audit

Encl.

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2014 ELECTRICITY DISTRIBUTION RATES

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

EB-2013-0127

January 15, 2014

Board Staff Submission
Espanola Regional Hydro Distribution Corporation
2014 IRM Rate Application
EB-2013-0127

Introduction

Espanola Regional Hydro Distribution Corporation ("ERHDC") filed an application (the "Application") with the Ontario Energy Board (the "Board") on October 18, 2013, seeking approval for changes to the distribution rates that ERHDC charges for electricity distribution, to be effective May 1, 2014. The Application is based on the 2014 Incentive Regulation Mechanism ("IRM").

The purpose of this document is to provide the Board with the submissions of Board staff based on its review of the evidence submitted by ERHDC.

By way of preliminary submissions on the various models and workforms filed with the Board, Board staff makes the following submission.

The Application

RTSR Workform

ERHDC completed the RTSR Workform and Board staff has no concerns with the data supporting the updated Retail Transmission Service Rates proposed by ERHDC.

On January 9, 2013 the Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2014, as shown in the following table:

2014 Uniform Transmission Rates

Network Service Rate	$3.82 per kW
<u>Connection Service Rates</u>	
Line Connection Service Rate	$0.82 per kW
Transformation Connection Service Rate	$1.98 per kW

Board staff will update the the RTSR Workform at the time of the Decision in this proceeding.

Deferral and Variance Account Disposition

ERHDC's total Group 1 Deferral and Variance Account balances amount to a credit of $145,045. The balance of Account 1589 – Global Adjustment is a debit of $151,308, and is applicable only to Non-RPP customers. These balances also include interest calculated to April 30, 2013. Based on the threshold test calculation, the Group 1 Deferral and Variance Account balances equate to $0.0023 per kWh which exceeds the threshold, and as such, ERHDC requested disposition of these Accounts over a two-year period. ERHDC stated that a two-year recovery/refund period from May 1, 2014 to April 30, 2016 is consistent with the 2012 disposition rate rider in effect until April 30, 2016. ERHDC further stated that a two-year period would mitigate rate impacts.

Board staff has reviewed ERHDC's Group 1 Deferral and Variance Account balances and notes that the principal balances as of December 31, 2012 reconcile with the balances reported by ERHDC pursuant to the *Reporting and Record-Keeping Requirements*. Also, the pre-set disposition threshold has been exceeded. Accordingly, Board staff has no issue with ERHDC's request to dispose of its 2012 Deferral and Variance Account balances at this time over the requested two-year period.

Board staff makes a detailed submission on the following matter:

- Incremental Capital Module ("ICM"); and,
- Lost Revenue Adjustment Mechanism for Pre-2011 CDM Activities

Incremental Capital Module ("ICM")

<u>The Request</u>

ERHDC proposed to recover, through an ICM, the incremental capital costs of $2,062,500 associated with the construction of a new municipal substation plus a required 44kV line.

ERHDC proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery ($168,193) on the basis of distribution revenue. ERHDC proposed to recover these amounts by means of fixed and variable rate riders with a sunset date of April 30, 2017. ERHDC is scheduled to file its next rebasing application for 2016 rates.

Eligibility Criteria

The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") requires that incremental capital expenditures satisfy the eligibility criteria of materiality, need and prudence in order to be considered for recovery prior to rebasing. To qualify for an ICM, applicants must demonstrate that amounts exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor, must be clearly non-discretionary and the amounts must be outside of the base upon which rates were derived.

(i) Materiality

ERHDC has claimed a total incremental capital of $2,062,500. This represents 85% of ERHDC non-discretionary 2014 capital-budget of $2,415,863. ERHDC has calculated the materiality threshold to be $293,556 using the formula established by the Board. Based on this threshold and a total non-discretionary budget for 2014 of $2,415,863, the amount eligible for incremental funding is $2,122,307 ($2,415,863 total non-discretionary capital budget minus a threshold of $293,556). In response to Board staff interrogatory #5, ERHDC confirmed that the Incremental Capital Workform as well as the Rate Generator will be updated to reflect the new price cap index parameters once issued by the Board.

(ii) Project Need and Prudence

ERHDC indicated that the incremental capital expenditures are related to the construction of a new municipal substation scheduled to be in-service by the fall of 2014. The new substation and 44kV line are being constructed to provide additional capacity as well as act as a contingency for ERHDC's three other substations. ERHDC stated that the new substation is critical to ERHDC's infrastructure. EHRDC provided evidence that ERHDC's present capacity matches almost exactly the winter loading requirements with no contingency for failure or maintenance by the remaining stations. ERHDC stated that a Condition Assessment Study performed in 2008 indicated that all three of the existing substations are approaching the end of their useful life. A

Substation Contingency Report prepared in 2010 by Costello Associates indicated that winter-time failure would most likely result in prolonged lengthy outages and rotating blackouts, lasting several days. In addition to adding capacity, ERHDC noted that the new municipal substation will be compatible with any level of automation or SCADA. EHRDC current substations do not have this compatibility.

In further discussion on the need for the station, ERHDC noted in response to VECC IR#5 that while annual energy usage has been very steady over the past ten years, summer demand has steadily increased since 2008. The Applicant noted that one possible explanation for this summer demand increase is the increased use of air conditioners by residential customers and additional refrigeration for new commercial loads. ERHDC stated that the impact of the summer demand is significant in that it is now higher than the capacity of the existing substations when one of the two 5000 kVA substations is out of service. Any serious failure at either MS-1 or MS-2 during summer or winter peak conditions will result in a shortfall of station capacity.

In October 2013, ERHDC retained the services of Costello & Associates to provide advice on the technical details of the new substation. A Municipal Substation Report ("2013 Report") was prepared. The 2013 Report concluded that ERHDC should design and construct a new municipal substation to provide additional capacity for system growth as well as providing a necessary system security for an unplanned station failure at one of the existing substations. The 2013 Report stated that this is consistent with current Ontario LDC planning practices.

ERHDC provided an evaluation of the following alternatives as part of the 2013 Report:

1. Expand the existing station – Stations MS-1 and MS-2 at 5000kVA are at maximum design capacity for 4 kV, while MS-3, rated 3000kVA could increase its capacity to 5000kVA.
2. Purchase Spare Transformer – ERHDC could purchase and store a spare transformer to be used as an emergency replacement in the event of failure at one of the existing station transformers.
3. New Substation - Build a new 5000kVA substation in the south-west area of Espanola, land acquisition, and building of a 44kV supply line. Three possible scenarios for doing so are set out below:

   a. Install a new substation with the same design as the existing station ($1.45M)
   b. Construction of a substation building, housing indoor metalclad switchgear, stand-alone protection and control rack and a SCADA/P&C/Communication rack ($2.75M).
   c. Install Outdoor 44kV Padmounted Switchgear, Underground Construction Padmounted Reclosers and isolating Switches, Underground 4.16KV Risers x 3 ($1.78M).
4. Do Nothing

Based on the recommendation by Costello and Associates, ERHDC selected option 3c, the construction of a new substation and the required 44kV line to provide additional capacity and increase supply security. Board staff asks that ERHDC confirm that the estimate for option 3c includes protection and control and a SCADA/P&C/Communication rack in exhibit 12.

ERHDC submitted that a failure to approve the incremental capital rate riders would have short-term financial implications for ERHDC. ERHDC stated that it would have to evaluate the progress of the construction, which might need to be halted until ERHDC would be eligible to re-base in 2016. They further stated that without the ICM rate rider, ERHDC would experience difficulty meeting the obligations of an Infrastructure Ontario loan, which was secured for this project as well as experiencing some short-term financial implications. .

The incremental Revenue Requirement Calculation

(i) The Half Year Rule

ERHDC did not apply the half year rule when calculating the incremental revenue requirement associated with the allowable ICM amount, since ERHDC is not scheduled for rebasing until 2016.

(ii) The Capital Structure

ERHDC used a 60% debt and 40% equity deemed capital structure and Board-approved cost of capital parameters when calculating the revenue requirement associated with the incremental capital expenditures.

ERHDC used default price-cap index of 0.58% (Inflation factor 1.6% less productivity 0.72% less stretch factor 0.3%).

Submission

Eligibility Criteria

Materiality

Board staff notes that EHRDC filed its ICM workform with a default price cap index of 0.58%. On November 21, 2013 the Board issued its Report (EB-2010-0379) *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* ("Price Cap IR Report"). Accordingly, the inflation factor for 2014 rates is 1.7%. Based on the total cost benchmarking model developed by Pacific Economics Group Research, LLC, the Board determined that the appropriate value for the productivity factor is zero percent. The Board also determined that the stretch factor can range from 0.0% to 0.6% for distributors selecting the Price Cap IR option, assigned based on a distributor's cost evaluation ranking. In the Price Cap IR Report, the Board assigned ERHDC a stretch factor of 0.15%. The resulting price cap index is 1.55% (1.70% - 0.15%).

Based on this updated price cap index, Board staff calculates the revised materiality threshold to be $335,084. The revised amount eligible for incremental capital funding would then be $2,080,779 (the total non-discretionary capital budget of $2,415,863 less the revised materiality threshold of $335,084). The requested amount of $2,062,500 for the new substation and 44kV line is clearly above the materiality threshold and within the amount eligible for incremental funding.

Based on this calculation, the total requested amount of $2,062,500 is eligible as a basis for ERHDC's incremental revenue requirement calculation.

Project Need and Prudence

With respect to the prudence of the investment, ERHDC considered four alternatives (as described above) in the 2013 Report. The first two alternatives, namely the expansion of existing stations and the purchases of spare transformers were not considered feasible. Instead ERHDC option 3c, the construction of a new substation with SCADA compatibility.

In the Chapter 3 of the *Filing Requirements For Electricity Distribution Rate Applications* (the "Filing Requirements") the Board states that an Applicant should provide "Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (but not necessarily the least initial cost) for the ratepayers". Board staff notes that ERHDC did not provide a cost estimate/business case for option one and two. Board staff submits ERHDC should provide a cost comparison between the various options, including the 'Do nothing' option.

Otherwise, Board staff takes no issue with the design of the substation selected by ERHDC.

With respect to the need and timing, Board staff has no concerns subject to confirmation that the new substation will be used and useful in 2014.

<u>The Incremental Revenue Requirement Calculation</u>

(i) The Half Year Rule

The Board's general guidance on the application of the half-year rule is provided in the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* dated September 17, 2008. In this report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IRM plan term. Since ERHDC is scheduled to be rebased in 2016, Board staff submits that ERHDC is correct in not applying the half-year year.

(ii) The Capital Structure

Board staff submits that the capital structure and the cost of capital parameters used are consistent with *Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications*, dated July 17, 2013 (“the Filing Requirements”).

Board staff submits that the revenue requirement calculation of $168,193 provided by ERHDC is consistent with the Filing Requirements.

Recovery of the Incremental Revenue Requirement

ERHDC proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery ($168,193) on the basis of a combination of fixed and variable rate riders. In response to Board staff interrogatory #6b, ERHDC confirmed that the proposed fixed/variable split is consistent with the split used to calculate ERHDC’s current Board-approved distribution rates.

ERHDC, in its Application, requested a sunset date of April 30, 2017 and noted that it expects to file a Cost of Service application for the 2017 rate year. In response to Board staff interrogatory #2 ERHDC confirmed that its current IRM plan term is 4 years and that it is scheduled to rebase in 2016. ERHDC agreed to forgo a defined sunset date and establish a rate rider that would be effective until the next cost of service-based rate order. The rate riders would be in place until such time.

Board staff notes that the Board previously approved in the case of Guelph Hydro (EB-2010-0130), Oakville Hydro (EB-2010-0104) and Centre Wellington (EB-2011-0160) an allocation of the revenue requirement on the basis of distribution revenue and the recovery of the incremental annual revenue requirement amount by means of a variable rate rider only. Board staff is of the view that a variable rate rider is administratively more straightforward than the additional complexities of rider with fixed and variable components. The stability of energy consumption levels by ERHDC would present little risk to recovering the ICM revenue amounts.

Lost Revenue Adjustment Mechanism for Pre-2011 CDM Activities

Section 13.6 of the Board’s *Guidelines for Electricity Distributor Conservation and Demand Management* (the “CDM Guidelines”) issued on April 26, 2012 outlines the information that is required when filing an application to recover LRAM amounts related to pre-CDM Code, or pre-2011, CDM Activities.

Espanola has requested recovery of an LRAM amount of $160,270 that includes lost revenues for 2006, 2007, 2008, 2009, and 2010 CDM programs from January 1, 2006 to April 30, 2012.

Espanola rebased in 2012 and had an updated load forecast approved by the Board that included a CDM component to reflect expected energy savings from its 2011-2014 CDM programs. Prior to its 2012 rebasing, Espanola rebased in 2008 (EB-2007-0901) but did not include a CDM component in its load forecast at that time. Board staff notes that the Board's 2008 CDM Guidelines (EB-2008-0037, March 28, 2008) were not issued until after Espanola filed its 2008 cost of service application. Board staff supports the recovery of the requested LRAM amount of $160,270 as Espanola was either under IRM during the years related to its request or did not otherwise have an opportunity to recover the lost revenues.

Board staff notes that this is consistent with what the Board noted in its decision on applications from PUC (EB-2011-0101), PowerStream (EB-2011-0005) and Brantford (EB-2011-0147).

All of which is respectfully submitted