2012 ELECTRICITY DISTRIBUTION RATES

Espanola Regional Hydro Distribution Corporation

EB-2011-0319

STAFF SUBMISSION

July 16, 2012

INTRODUCTION

Espanola Regional Hydro Distribution Corporation ("ERHDC" or the "Applicant") is a licensed electricity distributor serving the Town of Espanola and the Township of Sables-Spanish Rivers, which has a total population of approximately 8,700. ERHDC filed its 2012 rebasing application (the "Application") on February 15, 2012. ERHDC requested approval of its proposed distribution rates and other charges effective May 1, 2012. The Application was based on a future test year cost of service methodology.

The Vulnerable Energy Consumers' Coalition ("VECC") was granted intervenor status. The proceeding has been conducted through written discovery.

This submission reflects observations and concerns which arise from Board staff's review of the pre-filed evidence and interrogatory responses provided by ERHDC and is intended to assist the Board in evaluating ERHDC's application and in setting just and reasonable rates.

THE APPLICATION

In its original application, ERHDC requested a service revenue requirement of $1,810,263 (or a base revenue requirement of $1,670,364[1]). In response to a Board staff interrogatory[2] filed on June 8, 2012, ERHDC revised its service revenue requirement to $1,788,572 (or a base revenue requirement of $1,648,673). Board staff has drafted this submission with the understanding that this revised number is the final requested service revenue requirement for 2012 rates. The updated proposed rates are set to recover a revenue deficiency of $423,422. The following is a breakdown of ERHDC's 2012 test year revenue requirement from its June 8, 2012 updated evidence:

[1] Base revenue requirement is the service requirement less revenue offset of $139,899.
[2] Response to Board staff interrogatory # 36

Table 1
2012 Test Year Revenue Requirement

	As Filed February 15, 2012 MIFRS basis	As Updated June 8, 2012 MIFRS basis
OM&A Expenses	$1,372,624	$1,372,624
Amortization/Depreciation	$ 145,621	$ 143,296
Income Taxes (Grossed up)	$ 10,176	$ 9,329
Return		
Deemed Interest Expense	$ 122,309	$ 108,407
Return on Deemed Equity	$ 159,533	$ 154,916
Service Revenue Requirement	$1,810,263	$1,788,572
Revenue Offsets	$ 139,899	$ 139,899
Base Revenue Requirement	$1,670,364	$1,648,673

LOAD FORECAST

Exhibit 3 of the Application discusses how the load forecast and customer counts are developed.

Customer Forecast

ERHDC is seeking Board approval for a test year customer forecast of 4,410 customers/connections. The test year forecast is approximately 0.4% higher (or 18 customers/connections) than the 2010 actual. The forecast is derived by applying the class specific historic annual growth rate for the bridge and test years. The following table summarizes customers/connections forecast for 2012:

Table 2

Customer Count Forecast 2012 Test Year Customer Count Forecast (Exhibit 3/ Tab 2/ Schedule 1/ Page 4/ Table 3-4)

Rate Classes	**No. of Customers/Connections**
Residential	2,847
GS < 50 kW	425
GS > 50 kW	27
Street Lighting	1,053
Unmetered Scattered Load	32
Sentinel Lights	26
Total	4,410

Discussion and Submission

Board staff notes that ERHDC's customer forecast shows a 0.2% annual average growth from the 2010 Actual Year to 2012 Test Year. This is not significantly out of line with the 0.1% average annual customer growth experienced during the 2004 to 2010 period. Board staff has no concerns with the 2012 customer forecast as proposed by ERHDC.

Volume Forecast

ERHDC is seeking Board approval for a test year forecast of 62,249,997kWh or 62.2GWh. This represents a 2.4% increase from 2010 actual.

To develop its load forecast, ERHDC used a multifactor regression model to determine the relationship between historical load with weather data and calendar related events. ERHDC presented the comparison of the results of the model with actual system load for the period from 2003 to 2010. This evidence indicates that the percentage difference between the model estimate and actual load ranged from -1.4% to +1.8% over the regression range.

The following were used as the inputs for the model to generate the weather-normalized system purchases for 2011 and 2012:

- 8 year average (2003 – 2010) Heating Degree Days ("HDD") and Cooling Degree Days ("CDD"), Sudbury Station; and
- Calendar information related to the spring/fall flag (binary variable).

ERHDC made adjustments to account for CDM totaling 522,000 kWh to the 2012 Test year forecast. This CDM adjustment represents 20% of the cumulative energy saving targets for ERHDC. The class-specific forecasts (including the downward adjustment for CDM impacts) are summarized in the following table:

Table 3

2012 Test Year Load Forecast (Exhibit 3/ Tab 2/ Schedule 1/ Page 4/ Table 3-4)	
Rate Classes	**kWh**
Residential	32,680,721
GS < 50 kW	11,265,899
GS > 50 kW	17,442,772
Street Lighting	623,166
Unmetered Scattered Load	213,280
Sentinel Lights	24,161
Total	62,249,997

Discussion and Submission

The Applicant's forecast is slightly less than the average actual consumption for the period from 2003 to 2010, which was 62,808,073 kWh (a 0.9% decrease). Board staff notes that the difference is mainly due to the CDM adjustment and, as such, staff has no concerns with the proposed test year load forecast.

In regards to the CDM adjustment, Board staff has noted that distributors generally include 20% of their CDM targets into the load forecast when rebasing in 2012. The Board has accepted this approach in other distributors' load forecast proposals.[3] Board staff submits the inclusion of 552,000 kWh of CDM activity in its load forecast is reasonable.

OPERATIONS, MAINTENANCE AND ADMINISTRATION ("OM&A")

Background

For the 2012 test year, ERHDC is requesting Board approval of $1,372,624 in OM&A expenses excluding taxes and amortization expenses. This represents a 16.5% increase over the 2011 Bridge year and a 33.4% increase over 2010 actual. The following table summarizes ERHDC's OM&A expenses by year.

[3] Board's decision on Hydro 2000's 2012 cost of service application (EB-2011-0326), page 5

Table 4

	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Operation	$237,431	$252,410	$316,994	$195,045	$244,601	$249,346
Maintenance	$187,326	$198,999	$254,990	$283,052	$315,008	$397,158
Billing and Collecting	$254,686	$265,565	$283,165	$274,956	$305,760	$371,722
Community Relations	$2,000	$1,800	$815	$636	$1,000	$1,000
Administrative and General	$282,787	$285,113	$252,665	$275,029	$312,069	$353,398
Total OM&A	$964,230	$1,003,887	$1,108,629	$1,028,718	$1,178,438	$1,372,624
Year to year % change			*10.4%*	*-7.2%*	*14.6%*	*16.5%*
% change as compared to 2008 Approved		*4.1%*	*15.0%*	*6.7%*	*22.2%*	*42.4%*

Discussion and Submission

Transition to IFRS

In its original application, ERHDC provided an estimated total cost of $50,000 for consulting services for its transition from CGAAP to IFRS to be recovered over a 4 year period. ERHDC included the estimated $12,500 IFRS costs in the 2012 OM&A expenses.[4]

In its response to a Board staff interrogatory,[5] ERHDC explained that ERHDC has not incurred incremental administrative IFRS transition costs in 2012. In addition, ERHDC expects to implement IFRS on January 1, 2013 instead of January 1, 2012 as originally planned.

Responding to Board staff interrogatories, ERHDC stated that it is not planning to implement any aspect of IFRS in 2012.[6] In its responses, ERHDC agreed to remove the $12,500 IFRS costs from the 2012 OM&A expenses and use the Board approved Account 1508, Other Regulatory Asset, Sub account Deferred IFRS Transition Costs to

[4] Exh. 4/Tab 2/Sch. 5/page 4

[5] Response to Board staff interrogatory #39**,** Parts a, c, and d, dated June 8, 2012

[6] Supplemental response to Board staff interrogatory #1, parts a and d, and interrogatory #2, dated June 25, 2012.

record the one time administrative incremental IFRS transition costs for review and disposition at a later date.

Board staff concurs with ERHDC in removing the estimated $12,500 IFRS costs from the 2012 OM&A expenses. Board staff notes that the removal of this cost is not reflected in the updated revenue requirement number identified earlier in this submission. ERHDC should follow the APH FAQ instructions (October 2009, A.1) in recording the one time administrative incremental IFRS transition costs in 2013.

Vegetation Management

ERHDC provided a revision to its tree trimming costs in the following table.

Table 5[7]

Year		2008	2009	2010	2011	2012	2013	2014	2015
13km Bass Lake Road – One time	Costs					$37,500	$37,500	$37,500	$37,500
	Costs / km					3.25km $11,538/km	3.25km $11,538/km	3.25km $11,538/km	3.25km $11,538/km
13km Bass Lake Road – Ongoing	Costs				$10,000				
	Costs / km				1 km $10,000/km				
All other lines	Costs	$64,272	$100,443	$135,566	$113,916	$148,501	$148,501	$148,501	$148,501
	Costs / km	28km $2,295/km	36km $2,790/km	34km $3,987/km	11km $10,356/km	14km $10,607/km	14km $10,607/km	14km $10,607/km	14km $10,607/km
Total	Costs	$64,272	$100,443	$135,566	$123,916	$186,001	$186,001	$186,001	$186,001

ERHDC proposes a one-time tree trimming cost of $150,000 specifically for Bass Lake Road which requires extensive trimming, removal, and management of brush. In its application, ERHDC amortizes this cost over a 4 year recovery period, which results in $37,500 per year. ERHDC explained that in 2009, the Bass Lake Road area was not identified as a priority for tree trimming and limited resources had prevented the necessary concentration of effort on the Bass Lake round section.[8] Board staff has

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[7] Addition Information to response Board staff interrogatory # 9, dated June 28, 2012
[8] Response to Board staff interrogatory # 9 (a)

reviewed the evidence provided by ERHDC and has no concerns with this expenditure. However, staff has concerns with the proposed costs for all other lines.

ERHDC is planning to establish a tree trimming cycle of three years which represents average annual clearing of approximately 40km of primary line plus associated secondary line and services.[9] Board staff notes that Table 5 shows that the tree trimming costs per km for all other lines in 2008 was $2,295/km. However in 2010, the costs per km had increased to $3,987/km. This represents a 74% increase as compared to 2008. Furthermore ERHDC is proposing further increases to $10,607/km in 2012. It is Board staff's view that this substantial increase in the test year has not been well justified or explained, nor has the requirement for accelerating the pace of the tree trimming cycle. Board staff notes that ERHDC has not provided documentation to support the increase for all other lines. Such evidence could include expected impact on reliability if less tree trimming is done or higher costs to respond to tree-related outages. In the absence of more clarifications from ERHDC in its reply submission justifying both the quanta and timing of the tree trimming activity proposed, Board staff submits that the Board may wish to deem an amount of $42,000 which represents the average of 2008-2010 tree trimming costs ($3,024 per km for 14 km as reported in table 5 for 2012).

As such the total tree trimming costs for 2012 should be at the level of $83,500, including the costs for Bass Lake road.

<u>Overall Increase</u>

As shown in Table 4, the proposed 2012 OM&A represents a 42.4% increase as compared to 2008 Board Approved OM&A. This represents an annual average increase of approximately 11%. However, in 2010, the OM&A amount represents an increase of 6.7% as compared to 2008 Board Approved OM&A. On an annual basis, this represents only an average increase of 3.4%.

If ERHDC's OM&A is reduced for the items identified by Board staff, the 2012 OM&A will represent a 30% increase as compared to 2008 Board Approved, which also represents approximately a 7.5% annual increase from 2008. Even this reduced 2012 OM&A is still higher than ERHDC's historical annual increase as compared to the 2008 Board approved. Since ERHDC has identified that significant new and ongoing costs were

[9] Response to Board staff interrogatory # 9 (d)

introduced in the test year such as smart meter operating costs, there appears to be some justification for a somewhat higher than normal increase.

RATE BASE

Background

ERHDC is requesting approval of $4,246,610 for the 2012 rate base. This amount represents a 46.0% increase from ERHDC's 2010 actual and a 56.0% increase from its 2008 approved. Changes in rate base from 2008 to 2012 are shown in following table.

Table 6

	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test (Updated)
Rate Base	$2,721,381	$2,771,158	$2,759,870	$2,909,129	$3,447,134	$4,246,610
% change as compared to prior column		1.8%	-0.4%	5.4%	18.5%	23.2%

Capital Expenditures

ERHDC is projecting 2012 capital expenditures of $1,025,592 and this expenditure includes smart meter costs of $655,906.

Discussion and Submission

Table 7 lists the percentage change in the capital expenditures from 2008 to the 2012 test year.

Table 7

	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Capital Expenditures	$232,704	$152,290	$605,655	$395,865	$1,025,592
% change as compared to prior year		-34.6%	297.7%	-34.6%	159.1%

Board staff observes that the historic capital expenditures have fluctuated significantly. However, Board staff also notes that for a small utility a single project could increase the total capital expenditures by a considerable amount. For example, ERHDC's proposal to replace a bucket truck in 2012, at a cost of $190,000, represents more than 50% of non-smart meters related expenditures. Board staff notes that the capital expenditures for 2012 excluding smart meters expenditures would be $369,686. Staff also notes that the average of the historic capital expenditures (2008 - 2010) is about $330,000. Board staff has no concerns with respect to proposed capital expenditures with the exception of smart meters expenditures which are discussed separately in this submission.

ERHDC provided the reliability statistics for 2008 - 2010. The reliability statistics, SAIDI and SAIFI, are improving and the results of 2010 are showing a better performance than the average of the previous years. Board staff notes that the improved reliability is also supported by the decrease in the number of outages occurring in recent years.[10] Board staff takes no issue with the evidence provided.

ERHDC has filed an Asset Condition Assessment and an Asset Management Plan, dated November 2011 which included the overall capital investment required for the next 10 years (2012 – 2021) for asset sustainment. The overall 10 year capital investment plan[11] indicated that $900,000 is going to be required for stations in 2012 and 2013, and $375,000 going forward from 2014 to 2017. However, the evidence indicates that ERHDC had not included increased capital expenditures in 2012 for distribution stations; ERHDC explained that due to time constraints the capital expenditures would not be started until 2013 to address the major deficiencies in the distribution stations.[12]

Board staff's view is that ERHDC has extensively documented the condition of its assets and the program to address the required capital expenditures in the next 10 years.

[10] Response to Board staff interrogatory # 4 (a)
[11] Exh. 3/Tab 3/Sch. 1/page 51 - 52
[12] Exh. 3/Tab 3/ Sch. 1/page 1

Green Energy Act Plan (GEA Plan)

ERHDC is applying for approval of its Basic GEA Plan but is not seeking any cost recovery in this application.[13] ERHDC explained that there are no upgrades to its distribution feeders proposed in this application.[14] ERHDC provided a summary of a small number of microFIT and FIT generation activity in its service area and indicated whether ERHDC's system is capable of supporting them. In addition, ERHDC chose to include certain activities in its GEA Plan which appear to be non green energy related. ERHDC's GEA Plan is summarized under three headings: Renewable Project Applications; Distribution Feeders Assessment; and Substations Constraints and Mitigation Plan.

Renewable Project Applications

In response to a Board staff interrogatory,[15] ERHDC updated the status of the renewable projects applications and reported that of the 19 MicroFIT and FIT applications received since implementation, the following occurred:

- 1 Micro-Fit connected;
- 6 terminated;
- 4 pending connections (some since 2010);
- 3 submitted to the OPA; and
- 5 pending LDC Offers to connect.

Distribution Feeders Assessment

ERHDC owns and operates distribution feeders at three voltage levels:

- *a single 44 kV line* that is supplied from Hydro One owned Espanola TS and feeds three (3) 44 k to 4 kV distribution stations, with total of ten 4 kV feeders; and
- two 12.5 kV distribution feeders embedded into Hydro one service territory that supply the towns of Webwood and Massey.

[13] Exh. 2/Tab 3/Sch. 2
[14] Response to Board staff interrogatory # 18 (b)
[15] Response to Board staff Interrogatory # 19 (a) and (b)

According to the GEA Plan, the distribution system reveals no major constraints in the existing 4 kV, 12.5 kV and 44 kV distribution lines to accept Micro FIT or FIT green energy connections.[16]

Substations Constraints and Mitigation Plan

According to the Applicant's consultant, the 44 kV to 4 kV step-down distribution stations are the weakest link in ERHDC's distribution system and would become a constraint in the grid's ability to accept small or medium sized FIT connections.[17]

According to the Applicant's consultant, there are two specific problems in design configuration of the distribution stations that would hinder the connection of FIT and Micro-FIT connections:

- The distribution stations are not currently equipped with circuit breakers or reclosers for feeder protection, but employ manually operated fused disconnect switches. The existing design will not permit automatic operation of anti-islanding protection and control devices, per IEEE Standard 1547.
- There are no SCADA communications means available for remote monitoring and automated control of distribution feeders.

The GEA Plan identified steps to remove the major constraints for renewable generation connection and smart grid development.[18] These mitigation steps rely almost exclusively on a report entitled "Asset Condition Assessment & Asset Management Plan".[19] The mitigation plan calls for rebuilding of the three noted 4 kV distribution stations (MS1, MS2, and MS#3) over a 10-year period.

ERHDC is also building a new substation (MS 4) to meet load levels in the event of a single contingency of a substation failure.[20] ERHDC's pre-filed evidence listed the investments in a 10 year investment plan[21] which totaled $ 4.05 million for the four substations.[22]

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[16] Exh. 2/Tab 3/Sch.2/page 3 (line 42) to page 4 (line 7)
[17] Exh. 2/Tab 2/ Sch. 2/page 4/ lines 21 -39
[18] Exh. 2/Tab 3/Sch. 2/page 4 - 6
[19] Exh. 2/Tab 3/Sch. 1
[20] Exh. 2/Tab 3/Sch. 1/page 98 – 104 – Espanola Regional Hydro – Station Contingency Review
[21] Exh. 2/Tab 3/Sch. 2/page 5 - 6
[22] Exh. 2/Tab 3/Sch. 1/page 51-52

Discussion and Submission

ERHDC notes that the distribution lines in ERHDC's system are in good shape to connect renewable generation. However, the existing three distribution substations (MS1, MS2, and MS3) are in need of major investments to meet longer term system needs including renewable generation connections and smart grid development. ERHDC is also building a new substation (MS 4) to meet system needs in terms of meeting load levels in the event of a single contingency of a substation failure.[23]

ERHDC notes that investments in the existing three substations were stated in the pre-filed evidence to have three objectives: a) Provide adequate station capacity at 4 kV bus to meet the existing system loading needs and for future load growth; b) Replace distribution station assets reaching end of their useful service life; and c) Remove system constraints that hinder connection of renewable generation and are an impediment to smart grid development. [24]

In Board staff's view the investments in the three existing substations can be viewed as:

- replacement, like for like, for system elements reaching end of their useful service life i.e., meeting objective b) listed above; and
- additional investments to meet objective c). Such investment can be estimated where additional cost of replacement of system components such as cut-out fused disconnect switches with superior circuit breakers would allow future connection of renewable projects.

However, ERHDC was not able to provide estimates for the investments in the existing substations to categorize the investments into the noted two components i.e., replacement like-for-like and investments to allow for future connection of renewable projects. [25] Therefore, these investments in this proceeding should be characterized as sustainment investment, part of ERHDC's proposed asset management plan. Likewise, the new substation (MS 4) is needed to meet load and reliability needs of ERHDC's system.

[23] Exh. 2/Tab 3/Sch. 1/pages 98 - 104
[24] Exh. 2/Tab 3/Sch. 2/page 5
[25] Response to Board staff Interrogatory # 16 (b)

Board staff concludes that there are no investments in the five year horizon (2012-2016) of the GEA Plan that can be categorized as either directly related to connection of renewable generation or to investment in smart grid.[26] It is Board staff's understanding that these investments are part of ERHDC's Asset Management Plan and as the related assets come into service, they will flow into rate base in ERHDC's next cost of service application following a prudence review by the Board. As such, Board staff submits that the Board should not approve ERHDC's current plan as there is no cost recovery proposed at this time for the test year, or future years, nor has ERHDC properly classified its asset management activity. ERHDC has filed a GEA Plan supported by a letter from the OPA and an asset condition assessment. It is Board staff's view that ERHDC has thus met the requirements under the Board's Distribution System Planning Filing Requirements and that no further action is required at this time.

COST OF CAPITAL

Background

In Exhibit 5 of its Application, ERHDC proposed its test year Cost of Capital. This is summarized in the following table.

Table 8

Cost of Capital Parameter	**ERHDC's Proposal**
Capital Structure	60.0% debt (composed of 56.0% long-term debt and 4.0% short-term debt) and 40.0% equity
Short-Term Debt	2.08%
Long-Term Debt	5.01%
Return on Equity (ROE)	9.42%
Weighted Average Cost of Capital	6.66%

[26] Response to Board staff Interrogatory # 16 (b)

In its evidence and response to a Board staff interrogatory ERHDC confirmed that the short-term and long-term debt rate and the ROE will be updated based on the new parameters for May 1, 2012.[27]

On March 2, 2012, the Board issued a letter identifying the updated Cost of Capital parameters to be used in the 2012 rate year cost of service applications for rates effective May 1, 2012. These are summarized in the following table:

Table 9

Cost of Capital Parameter	**Updated Value for 2012 Cost of Service Applications for rates effective May 1, 2012**
Return on Equity (ROE)	9.12%
Deemed Long -Term Debt rate	4.41%
Deemed Short-Term Debt rate	2.08%

Discussion and Submission

Board staff notes that ERHDC has provided its updated rates to reflect the cost of capital parameters issued on March 2, 2012.[28] Board staff has no concerns with ERHDC's treatment of the cost of capital components.

COST ALLOCATION AND RATE DESIGN

Revenue-to-Cost Ratios

Background

ERHDC proposes to re-balance its class revenues as a result of its cost allocation results. The revenue-to-cost ratios of GS > 50kW class is currently above the Board's policy range with the current rates, and the Street Lights and Sentinel Lights classes are below the Board's policy range.

[27] Response to Board staff interrogatory # 20
[28] Response to Board staff interrogatory # 36

The following table provides ERHDC's current and proposed revenue-to-cost ratios and the Board's target ranges, as established in the Board's *Review of Electricity Distribution Cost Allocation Policy EB-2010-0219*.

Table 10
Revenue to Cost Ratio[29]

Customer Class	Updated Current Ratios	Proposed Ratios for Test Year	Board Target Lower Range	Board Target Upper Range
Residential	93.4%	95.2%	85.0%	115%
GS < 50 kW	113.9%	115.9%	80.0%	120%
GS > 50 kW	135.7%	120.0%	80.0%	120%
Street Lights	68.7%	70.0%	70.0%	120%
Sentinel Lights	68.3%	80.0%	80.0%	120%
Unmetered Scattered Load	114.3%	114.9%	80.0%	120%

Discussion and Submission

As indicated in the second column of the above table, ERHDC currently has three classes that have revenue-to-cost ratios outside the Board's target ranges. ERHDC proposed to move the revenue-to-cost ratio for GS > 50 kW to the ceiling of the target range. The Street Lights and Unmetered Scattered Load classes are currently below the target range and ERHDC proposed to move these classes to the floor of the respective target ranges.

Board staff has no concerns with the proposed revenue-to-cost ratios as they are all within the Board's target ranges.

[29] Response to Board staff interrogatory # 22 and VECC interrogatory # 21

Monthly Service Charges ("MSC")

Background

ERHDC's current and proposed monthly service charges are presented in the table below:

Table 11

	Monthly Service Charges	
Rate Classes	**Current**	**Proposed**[30]
Residential	$9.96	$13.70
GS < 50 kW	$17.95	$24.54
GS > 50 kW	$161.36	$190.93
Street Lights	$1.40	$1.93
Sentinel Lights	$1.29	$2.09
Unmetered Scattered Load	$8.82	$11.94

In its Application, ERHDC stated that it is appropriate to maintain the same fixed/variable proportions in the current rates to all customer classes. The proposed MSCs are below the ceiling for every class as indicated in the cost allocation model, except for the GS > 50 kW class.

Discussion and Submission

Board staff notes that although the proposed MSC for the GS > 50 kW class exceeds the upper bound of the MSC in past decisions,[31] the Board has noted that it will not require utilities to lower the existing MSC if they are above the ceiling. Board staff submits that ERHDC's proposal to maintain its fixed/variable proportion is reasonable.

[30] Response to Board staff interrogatory # 36
[31] Decision on Hydro One Brampton (EB-2010-0132), page 38, Decision on Kenora Hydro Electric Corporation Ltd., page 33

Retail Transmission Service Rates ("RTSR")

In response to a Board staff interrogatory ERHDC updated RTSRs to reflect expiration of rate riders which are under Hydro One Sub-Transmission classification.[32] The updated RTSRs are shown in the following table.

Table 12

Rate Classes	RTSR Network	RTSR Connection
Residential ($/kWh)	$0.0056	$0.0041
GS < 50 kW ($/kWh)	$0.0052	$0.0037
GS > 50 kW ($/kW)	$2.0890	$1.4334
GS > 50 kW – Interval Metered ($/kW)	$2.3482	$1.9855
Street Lighting ($/kW)	$1.5755	$1.1080
Unmetered Scattered Load ($/kWh)	$0.0052	$0.0037
Sentinel Lights ($/kW)	$1.5835	$1.1312

Discussion and Submission

Board staff has examined the revised RSTR work form provided by ERHDC and takes no issue with the revised RTSRs.

Low Voltage Charges

ERHDC is an embedded distributor of Hydro One Networks Inc. and is subject to Low Voltage ("LV") charges. In response to a Board staff interrogatory ERHDC revised its proposed LV costs from $144,544 to $229,288 and stated the revision is based on the current Hydro One rates.[33]

The Applicant allocated the LV costs to each class based on the Hydro One sub transmission charges forecast in 2012. The following LV charges for each class are determined by volumes derived from the 2012 load forecast.

[32] Response to Board staff interrogatory # 24
[33] Response to Board staff interrogatory # 23 (a)

Table 13

Rate Classes	Allocation to classes	Proposed LV Charges
Residential	$121,998	$0.0037/kWh
GS < 50 kW	$39,252	$0.0035/kWh
GS > 50 kW	$65,376	$1.4840/kW
Street Lights	$1,848	$1.0466/kW
Unmetered Scattered Load	$743	$0.0035/kWh
Sentinel Lights	$71	$1.0684/kW

Discussion and Submission

Board staff has reviewed the details of the proposed amount and confirmed the calculations are based on the latest approved Sub Transmission charges for Hydro One Network Inc. (EB-2009-0096), effective January 1, 2011. As such staff has no concerns with the LV costs proposed by the Applicant. However, since the proposed LV costs are approximately 14% of the proposed base revenue requirement, staff submits that ERHDC should identify in its reply submission whether it has explored any alternatives that could lead to a reduction of the LV costs in the future and that would benefit ERHDC's customers. If not, staff encourages ERHDC to explore this area and report on its findings in the next cost of service application.

Loss Factors

Background

ERHDC is proposing a Total Loss Factor ("TLF") of 1.0714 for secondary metered customers < 5,000 kW based on an underlying Distribution Loss Factor ("DLF") of 1.0527 and Supply Facility Loss Factor ("SFLF") of 1.0178. The proposed SFLF and DLF are based on the average of five historical years 2006 to 2010. ERHDC's actual DLF for the 2006 to 2010 period has fluctuated from a low of 1.0440 to a high of 1.0634. The currently approved TLF for secondary metered customers < 5,000 kW is 1.0543.

ERHDC indicated that it plans to investigate options to make system improvements to reduce the line losses.

Discussion and Submission

Board staff notes that the underlying Distribution Loss Factor ("DLF") for the recent years has decreased since 2006. However the DLFs were still above 5%. ERHDC states that it plans to investigate options to reduce line losses, yet no action was taken to this point. Board staff has concerns that ERHDC's proposed loss factors for 2012 are still above 5%, and proposed two options for the Board's consideration: first, the Board may wish to approve the proposed TLF and direct ERHDC to address any persistent DLF above 5% in the next cost of service application by developing and filing a plan to reduce losses. The second option is that the Board may wish to deem a DLF of 5% for purposes of this application and direct ERHDC to file a plan to reduce losses as part of its next cost of service application.

DEFERRAL AND VARIANCE ACCOUNTS

Balances Proposed for Disposition

ERHDC proposed to dispose Group 1 and Group 2 deferral and variance account balances as of December 31, 2010, and interest forecast to April 30, 2012.

The allocation factors used by ERHDC for the volumetric rate rider calculation are in accordance with the EDDVAR report (EB-2008-0046).[34]

The proposed amounts for disposition are presented below:

Table 14

Account #	Account Description	Disposition Amount
Group 1		
1550	LV Variance Account	($9,996)
1580	RSVA – Wholesale Market Service Charge	($137,250)
1584	RSVA – Retail Transmission Network Charge	$676
1586	RSVA – Retail Transmission Connection Charge	($9,298)
1588 - Pwr	RSVA – Power (excluding Global Adjustment)	$280,208
1588 - GA	RSVA – Power – Sub account -Global Adjustment	($5,199)

[34] *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)*, EB-2008-0046, July 31, 2009

Group 2		
1508	Other Regulatory Assets – Incremental Capital Charges	$2,409
1562	Deferred Payments in Lieu of Taxes	($26,978)
1592	PILs/Taxes Variances for 2006 and subsequent years	$8,443
1592 - ITC	PILs/Taxes Variance, Sub-account HST/OVAT Input Tax Credit	($7,888)
	Total Proposed for Disposition	**$105,854**

The debit balance of $105,854 is proposed to be recovered over a one year period.

Discussion and Submission

Board staff notes that the balances as of December 31, 2010 are consistent with ERHDC's RRR filings with the Board (except for account 1562, which is dealt with elsewhere in this submission). Board staff has no concerns with the proposed disposition.

Board staff submits that when preparing the draft Rate Order, ERHDC should ensure that the approved balances for account 1562 and account 1592 are combined with the remaining deferral and variance account rate riders.

PAYMENTS IN LIEU OF TAXES - PILS 1562

Background

The PILs evidence filed by ERHDC in this proceeding includes tax returns, financial statements, Excel models from prior applications, calculations of amounts recovered from customers, SIMPIL[35] Excel worksheets and continuity schedules that show the principal and interest amounts in the account 1562 Deferred PILs balance. In the pre-filed evidence, ERHDC applied to refund to customers a credit balance of $26,978 consisting of a principal credit amount of $24,804 plus related carrying charges of $2,174.

[35] SIMPIL is the acronym for spreadsheet implementation model for payments in lieu of taxes

Discussion and Submission

In determining the excess interest true-up variances in the SIMPIL models, the Board-approved maximum deemed interest of $96,738 was deducted from actual interest expense. Total interest expense from 2001 through 2003 was significantly lower than the maximum deemed interest and there was no excess interest. However, in 2004 and 2005, Espanola incurred interest expense that was higher than the maximum deemed interest. The table below was provided by ERHDC.[36]

Table 15

	Interest Expense per Financial Statements	IESO Costs	Interest on Regulatory Assets	Interest on PILS Assessment	Net Interest Expense for Interest Clawback
2004	173,677.32		(2,315.03)		171,362.29
2005	172,506.08	(4,897.81)	(4,275.56)	(4,984.02)	158,348.69

ERHDC stated its views on the components of interest expense as follows.

"ERHDC believes that interest expenses related to regulatory assets, IESO line of credit costs, and tax reassessments should be excluded from the excess interest clawback determination. In addition ERHDC believes it is unfair to treat costs related to IESO lines of credit as excess interest costs for similar reasons articulated above. Lines of credit are not reflected in the debt portion of capital structure on the balance sheet. As such they attract no debt return when rates are set."[37]

The Board has issued many recent decisions where the IESO stand-by charges have been considered to be interest expense for purposes of the interest true-up calculations.[38] Board staff submits that interest on regulatory asset variance accounts and on PILs assessments should be excluded from the true-up calculations to be consistent with decisions already made by the Board. Board staff submits that fees charged on IESO or other prudential letters or lines of credit should be included in the

[36] Exhibit 9/ Appendix A/ PDF page 722.
[37] Exhibit 9/ Appendix A/ PDF page 721.
[38] EB-2011-0174; EB-2011-0179; EB-2011-0147; EB-2011-0155; EB-2011-0197.

true-up calculations to be consistent with decisions already made by the Board. Board staff submits that the revised credit amount would be approximately $28,245 consisting of a principal credit amount of $25,910 plus related carrying charges of $2,335.

Board staff submits that the minimum income tax rates used by ERHDC in the SIMPIL models are correct for a utility its size. Board staff submits that the amounts ERHDC has calculated as PILs recoveries from customers are reasonable.

Board staff requests that ERHDC file active Excel SIMPIL models as part of its draft Rate Order that may be affected by the Board's decision in this case and a revised continuity schedule.

Smart Meters

ERHDC has installed 3,290 smart meters as of the end of 2010 and this represents 99.5% of its smart meter deployment. In 2011, ERHDC completed 100% of its smart meter deployment (3,307 smart meters). In its responses to Board staff interrogatories, ERHDC has updated and re-filed the smart meter model. ERHDC is requesting:

1. Disposition of all capital and operating costs to the end of 2011;
2. A class specific smart meter disposition rate rider ("SMDR") of $2.28 per month for each residential customer, $2.51 per month for each GS < 50 kW customer and $3.78 for each GS > 50 kW customer to dispose of the smart meter variance accounts which will recover the difference between the revenue requirement and the actual revenue collected to the end of April 2012 over a 2 year period;
3. A class specific stranded meter rate rider ("SMRR") of $1.04 per month for each residential customer, $1.37 per month of each GS < 50 kW customer and $4.30 per month for each GS > 50 kW customer over a 2 year period.

Discussion and Submission

<u>Prudence of Smart Meter Costs</u>

Based on the evidence on the record, Board staff has documented ERHDC's per meter costs in the following table:

Table 16

Description	Total Cost	Cost per Meter
Smart Meters and AMI Capital Costs	$655,539	$198.23
Capital Costs Above Minimum	$20,366	$ 6.16
Total Capital Costs	**$675,905**	**$204,39**
Smart Meters and AMI OM&A Costs	$106,633	$32.24
Number of Smart Meters installed	3,307	
Total Cost per installed Smart Meter		**$236.63**

Source: Response to Board staff interrogatory # 29-31, 35, revised smart meter model

Board staff observes that the above total per meter costs are reasonable as compared to the costs the Board has seen for most utilities that have filed applications to date.[39] Board staff takes no issue with ERHDC's documented costs for smart meters installed up to 2011. Board staff also notes that the corresponding capital costs have been included in rate base.

Board staff observes that ERHDC was authorized to deploy smart meters under O.Reg. 427/06 as amended by O.Reg. 238/08 in accordance with the London Hydro RFP process. It complied with the regulation and London Hydro RFP process for the procurement of smart meters and associated equipment and for services to install and operate the smart meters and associated equipment. Board staff considers that the documented costs are prudent.

Recovery Period of the Smart Meter Disposition Rate Rider

ERHDC proposed class-specific SMDRs to recover the revenue requirement over the 2007 to 2011 period of smart meters installed up to 2011 over a 2 year period. The SMDR also takes into account the actual revenue collected to the end of April 2012 through the Smart Meter Funding Adder. The net result is a recovery amount of $184,091 that would be recovered over the May 1, 2012 to April 30, 2014 period.

In response to a Board staff interrogatory, ERHDC confirmed that it used the following cost allocation methodology: [40]

[39] Niagara-on-the-Lake Hydro Inc. (EB-2012-0036), Midland Power Utility Corporation (EB-2011-0434)
[40] Response to Board staff interrogatory # 33

- Return (deemed interest plus return on equity) was allocated based on the number of smart meters installed by rate class;
- Amortization was allocated base on the smart meter costs by rate class;
- OM&A expenses were allocated based on the number of installed smart meters for each rate class;
- Payments in lieu of taxes (PILs) were allocated based on the revenue requirement allocated to each rate class before PILs; and
- Smart Meter Funding Adder revenue, including carrying charges, were allocated based on actual amounts collected from each rate class.

Board staff notes that cost causality should be the guiding principle when allocating costs to each class. Board staff is of the view that it is more appropriate to allocate the return based on the smart meter costs by rate class. Board staff submits that ERHDC should update its cost allocation to reflect the updated return calculation and provide the resulting SMDRs.

Stranded Meters

ERHDC provided the net book value of the stranded meters removed from service. ERHDC applied to recover $87,767 through class-specific rate riders over a 2 year period. Board staff notes that in its evidence ERHDC provided the Net Book Value ("NBV") by class for stranded meters. Staff has no concerns with the proposed amount nor with the SMRRs proposed.

LOST REVENUE ADJUSTMENT MECHANISM ("LRAM")

Background

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on March 28, 2008 outline the information that is required when filing an application for LRAM or SSM recovery.

ERHDC seeks to recover a total LRAM claim of $160,270, which includes $8,740 in carrying charges, to be recovered over a three-year period. The lost revenues include the effect of CDM programs implemented from 2006-2010. ERHDC has requested approval of these savings persisting until April 30, 2012.

Discussion and Submission

2006 to 2010 lost revenues

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

Board staff notes that ERHDC's last cost of service application was filed on November 6, 2007, prior to the issuance of the Board's CDM Guidelines which were issued on March 28, 2008. As ERHDC's last cost of service application was filed prior to the issuance of the Board's CDM Guidelines, the rules regarding LRAM and lost revenues in general were not available to ERHDC. Since ERHDC could not be reasonably expected to have adhered to direction from the Board regarding the inclusion of CDM effects in its load forecast as the CDM Guidelines were not yet available, Board staff supports the recovery of the requested LRAM amounts in 2006, 2007, 2008, 2009, and 2010.

Board staff notes that this is consistent with what the Board noted in its decision on the application from PUC (EB-2011-0101) for PUC's 2012 IRM adjustment.

2011 and 2012 lost revenues

Since the OPA has not completed the evaluations on the 2011 CDM programs, Board staff submits that it is premature to consider any lost revenues for 2011 or 2012.

Board staff requests that ERHDC provide an updated LRAM amount and subsequent rate riders that only includes lost revenues from 2006 to 2010 CDM programs for the years 2006 to 2010, and the associated rate riders.

MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS ("MIFRS")

PP&E Deferral Account

Background

ERHDC provided the Property & Plant Equipment (PP&E) Deferral account calculation as well as the adjustment required in the revenue requirement in its application.[41]

[41] Exh 6/Tab 2/Sch. 2/page 1, Table 6-4

ERHDC applied the rate of return on equity of 6.66% to reflect the adjustment on the revenue requirement as shown below in Table 1 below.

Table 17
PP&E Deferred Balance

IRFS 2011 NBV	$2,494,557
CGAAP 2011 NBV	2,400,062
Difference	94,495
Amortized over 4 years	23,624
Add: Rate of Return 6.66%	6,293
Amount included in the Revenue Requirement	29,917

Subsequently, in response to a Board staff interrogatory[42], ERHDC provided an update to the return component of the PP&E deferred balance using 6.20%. ERHDC provided the revised calculation for the PP&E deferred balance which is as follows:

Table 18
Revised PP&E Deferred Balance

IFRS 2011 NBV	$2,494,557
CGAAP 2011 NBV	2,400,062
Difference	94,495
Amortized over 4 years	23,624
Add: WACC 6.20%	5,859
Amount included in the Revenue Requirement	$ 29,483

Discussion and Submission

Board staff notes that ERHDC's most recent update reflects the WACC figure of 6.20% for the calculation of the PP&E deferred balance amount of $29,483. Board staff is

[42] Supplemental response to Board staff interrogatory #40, dated June 25, 2012

uncertain whether this update has been reflected in the updated revenue requirement. Board staff submits that ERHDC should clarify this and make the necessary adjustments in its 2012 revenue requirements given this recent update, if needed.

RATE MITIGATION

In response to a Board staff interrogatory, ERHDC filed an updated Revenue Requirement Work Form ("RRWF"), which included the bill impact calculation from current Board-approved (i.e. May 1, 2011) rates to ERHDC's updated proposed rates for 2012 for all the rate classes.[43] Board staff notes that the total bill impact for all the rate classes are more than 10% except for GS > 50 kW class. Board staff also notes that ERHDC did not file a rate mitigation plan with its pre-filed evidence, nor did it opine on this in response to the above interrogatory

Discussion and Submission

Board staff notes that a rate mitigation plan is required in keeping with the Board's filing requirements, which specify that a distributor will be required to file a mitigation plan for any class or group of customer whose total electricity bill is expected to increase by more than 10% over the previous bill amount.[44] Staff submits that depending on the outcome of the Board's decision, a mitigation plan may still be required to be filed as part of the draft Rate Order to address any class whose total bill impact is over 10%.

- All of which is respectfully submitted -

[43] Response to Board staff interrogatory # 36

[44] Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, dated June 22, 2011, page 44