Ontario

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2011 COS APPLICATION FOR RATES EFFECTIVE MAY 1, 2011.

Kenora Hydro Electric Corporation Inc.

EB-2010-0135

March 29, 2011

INTRODUCTION

Kenora Electric Corporation Inc. ("Kenora" or the "Applicant") is a licensed electricity distributor serving approximately 6,087 customers in the City of Kenora located in Northwestern Ontario. Kenora filed its 2011 rebasing application (the "Application") on November 1, 2010. Kenora requested approval of its proposed distribution rates and other charges effective May 1, 2011 or as soon as possible thereafter. The Application was based on a future test year cost of service methodology. Kenora's Hydro's 2006 rates were set on a Cost of Service basis and the subsequent years were under the Incentive Rate Mechanism.

The Board issued the Letter of Direction on November 23, 2010. The Vulnerable Energy Consumers' Coalition ("VECC") was granted intervenor status. Kenora did not receive any letters of comment.[1]

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

THE APPLICATION

Kenora is proposing a 2011 service revenue requirement of $3,208,191 (or a base revenue requirement of $2,850,945[2]). This represents a 23.3% increase over the 2006 Board approved service revenue amount of $2,322,919.[3] The revenue deficiency, calculated using 2010 approved rates, that Kenora seeks to recover through the rates proposed for 2011 is $990,070.

A break-out of Kenora's proposed revenue requirement is presented in the table below.[4]

1 Response to Board staff IR No.5
2 Base revenue requirement is the service revenue requirement less Other Revenue of $357,246.
3 Source: RP-2005-0020/ EB-2005-0384 Decision and Order (dated April 12, 2006) p. 5
4 In some instances throughout this submission there may be immaterial differences in the numbers. This is attributable to rounding.

2011 Revenue Requirement Components	
OM&A	$ 2,062,785
Amtz/Depreciation	$ 468,960
Property Taxes	$ 13,260
Capital Taxes	$ -
Income Taxes (grossed up)	$ 20,812
Other Expenses	$ -
Return - interest	$ 236,536
Return- ROE	$ 406,115
Service Revenue Requirement	$ 3,208,468
Revenue Offsets	$ 357,246
Base Revenue Requirement	$ 2,851,222

Kenora has calculated the following monthly bill impacts if the application is approved as filed.[5]

Delivery Charge Impact -increase in delivery costs over current rates- *			**Total Bill**	
			$ Impact	**% Impact**
	$ impact	**% impact**		
Residential @ 800 kWh	$ 9.45	32.92%	$ 10.96	10.04%
GS < 50kW @ 2000kWh	$ 15.39	31.71%	$ 17.67	6.88%
GS > 50kW @ 30,000kWh, 100kW	$ 119.29	15.53%	$ 114.01	3.13%
Streetlighting 550 connections	$1,103.43	28.80%	$ 1,178.24	7.22%
Unmetered Scattered Load 10,000 kWh	-$ 5.42	-4.41%	-$ 11.47	-1.08%
* includes monthy charge, variable charge, adders, riders and retail transmission				

In its interrogatory responses Kenora identified a number of situations which warranted a change to the numbers presented in the evidence as initially filed. The adjustments proposed by Kenora were confirmed in response to VECC interrogatory No. 47. The adjustments result in net decreases of $146,897 and

[5] Source: Exhibit 8-1-5 Appendix C

$73,500 in operating expenses and capital expenditures respectively.[6] Board staff notes that Kenora included reduced interest on long term debt in the amount of $74,776 in its calculation of the decrease in operating expenses.. This reflects Kenora's update on its Infrastructure Ontario financing plans and is addressed under the Cost of Capital section of this submission.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In response to Board staff interrogatory No. 7, Kenora confirmed that the revenue requirement amount proposed for 2011 was based on General Accepted Accounting Principles (GAAP) and that it will not be presenting financial statements under IFRS rules until the financial statements are prepared for the fiscal year ending December 31, 2012. Kenora also confirmed that no amounts were included in the proposed revenue requirement for IFRS transition costs and noted that transition costs are recorded in a sub account of 1508 (Other Regulatory Assets – IFRS Transition Costs).

Board staff has no concerns regarding the status of IFRS matters as described by Kenora. Staff expects the Board to issue guidance later this year to distributors with respect to addressing IFRS issues during IRM years.

LOAD FORECAST

Kenora's test year load forecast totals 107,843,068 kWh and 122,267 kW. This represents a decrease in system wide consumption of 0.9% from 2009 actuals. The proposed and actual volumes by customer class are set out in the table below.

LOAD VOLUMES	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Residential kWh	40,803,344	39,172,136	39,142,088	39,338,336	39,909,017	39,135,578	38,188,928
GS< 50 kW KWh	29,132,605	26,858,694	26,504,159	24,007,759	23,638,260	23,046,528	22,359,418
GS >50 kW kWh	41,264,080	41,350,695	43,467,433	45,059,368	43,454,274	44,508,715	45,342,066
GS >50 kW kW	93,517	106,089	108,299	113,852	108,940	114,389	116,530
Street lighting kWh	1,686,441	1,716,801	1,947,932	1,857,398	1,690,689	1,758,282	1,807,975
Street lighting kW	4,823	5,292	5,292	5,292	5,292	5,579	5,737
USL kWh	181,936	214,812	214,812	197,575	157,460	151,793	144,681
Total kWh	113,068,406	109,313,138	111,276,424	110,460,436	108,849,700	108,600,896	107,843,068
Total kW	98,340	111,381	113,591	119,144	114,232	119,968	122,267

Source: Exhibit 3 Tab 2 Schedule 1 p.20

[6] See attachment A

Load Forecasting – Methodology and Steps

Kenora noted, by way of introduction, that it utilized the same regression analysis used by a number of other distributors to predict future loads. The regression analysis is based on total historical electricity purchases and not on a monthly-billed individual rate class basis. Kenora views this method as appropriate since it allows for the relating of purchases with explanatory variables such as cooling and heating degree days within the same month; for Kenora billed load does not align with the explanatory variables. Once the method generates the total level of forecasted weather normalized purchases, and are loss factor adjusted, the results are then converted to kWh by rate class.[7]

Kenora anticipates that the Board will approve the forecast based on this methodology as it has for other distributors. Kenora pointed to the accuracy of the regression model. Between 2003 and 2009, except for 2005, the variance between predicted and actual volumes was less than 0.5% and averaged 0.15%. The variance was consistently one of over-prediction.

The steps Kenora undertook to prepare the 2011 load forecast are as follows:

First: A total system-wide weather normalized (purchased) energy forecast was developed using a multifactor regression model that incorporates historical load (8 years of system load data available, from 2002 to 2009), weather (heating & cooling days), economic data (GDP)[8], total customer numbers and calendar variables (days in the month, seasonality). Weather normalization is based on the average monthly degree days between 2002 and 2009. This resulted in a purchased load forecast of 113.270 GWh and 113.784 GWh for 2010 and 2011 respectively. [9]

Second: The energy forecast is adjusted by the proposed loss factor (4.3%) to derive the system-wide billed energy forecast for 2010 and 2011. This resulted in a billed energy forecast (weather normalized) of 108.6 GWh and 109.1 GWh for 2010 and 2011 respectively.

[7] Source: Exhibit 3-2 1 p.1-20
8 Economic growth is captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP") taken from the 2010 Ontario Budget dated March 25, 2010.
[9] Kenora also provided a forecast for 2011 using 10 and 20 year trend analysis. The resulting 2011 forecast is 113.590 MWh and 114.095MWh respectively or 0.2% lower and 0.3% higher than the forecast based on average weather over the past 8 years.

Third: The system-wide billed energy forecast is allocated by rate class using a forecast of customer numbers and historical use per customer patterns. The forecast was also adjusted for CDM targets set for Kenora and an anticipated drop in consumption.

Load Forecasting - Customer Growth

As indicated in the table below, Kenora is forecasting a decline in residential and GS < 50kW customer numbers for 2010 and 2011 as compared to 2009, and an increase in GS > 50 kW customers.[10] Street lighting connections remain constant and unmetered scattered load connections increase from 28 to 30. Based on the actual customer connections for 2010, it is apparent that the pre-filed evidence under-forecasted Residential and GS < 50kW customers and over-forecasted GS >50 customers.

CUSTOMERS & CONNECTIONS	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year	2010 Actual
Residential	4,980	5,029	5,012	4,781	4,783	4,728	4,674	4,770
GS <50kW	793	782	794	732	713	708	703	744
GS>50kW	58	61	66	66	70	72	75	69
TOTAL	5,831	5,872	5,872	5,579	5,566	5,508	5,452	5,583
Street Lighting	550	550	550	550	550	550	550	
Unmetered Scattered Load	3	28	28	28	28	29	30	
Grand Total	6,384	6,450	6,450	6,157	6,144	6,087	6,032	

Kenora used a geometric mean based calculation to forecast the 2010 and 2011 residential and general service customer levels. While the evidence seemed to indicate that the geometric mean was calculated using 2005-2009 actuals, in response to Board staff interrogatory No.16 Kenora noted that the geometric mean calculation was based on 8 years of actuals, 2002-2009.

Board staff submits that the customer forecast for 2011 should be updated to include 2010 actuals since this will improve the accuracy and currency of the 2011 forecast.

[10] In the table, the column on the extreme right shows the actual customer numbers for 2010. These were provided by Kenora in its response to VECC interrogatory No. 13.

To assess the impact of including 2010 actuals, Board staff has calculated the geometric mean for the most recent 8 years of actuals, 2003 to 2010, and the results appear in the extreme right column of the table below. As compared to the as filed forecast for 2011, updated Residential customer numbers are 1.2% higher, GS < 50 kW 5.1% higher and GS > 50 kW 6.7% lower.

CUSTOMERS	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	*2010 Bridge	* 2011 Test	2010 Actual	** 2011 Test
Residential	5,186	5,051	5,011	4,989	5,029	5,012	4,781	4,783	4,728	4,674	4,770	4,731
GS <50kW	749	803	794	797	782	794	732	713	708	703	744	736
GS>50kW	56	63	61	60	61	66	66	70	72	75	69	70
Total	5,991	5,917	5,866	5,846	5,872	5,872	5,579	5,566	5,508	5,452	5,583	5,537
Note: * 2002-2009 Geometric Mean based forecast												
** 2003-2010 Geometric Mean based Forecast												

Kenora may wish to respond whether the customer forecast presented above is an acceptable way of including 2010 actuals in the customer forecast calculation, assuming that in the first instance the customer forecast should be updated since the 2010 actuals are available.

Use per Customer

Kenora 's actual (non weather normalized) and bridge and test year forecast (weather normalized) of use per customer levels are presented in the table below.

AVERAGE USE PER CUSTOMER	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
(non weather normalized)								
Residential	8,096	8,126	7,787	7,810	8,228	8,344	8,277	8,171
GS <50kW	32,366	36,027	34,319	33,381	32,797	33,153	32,551	31,806
GS>50kW	544,008	554,318	677,880	658,597	682,718	620,775	618,176	604,561
Street Lighting	3,927	3,596	2,842	3,542	3,377	3,074	3,196	5,234
Unmetered Scattered Load	8,530	7,882	7,672	7,672	5,655	5,624	5,234	4,823

The calculation of the 2010 and 2011 forecasts included the following steps. A geometric mean of historical actuals was applied to the 2009 actual for each rate class. These were then totalled (the sum of forecasted use per customer times the forecasted customer number for each rate class) into an aggregate non-weather normalized forecast for 2010 and 2011. The non-weather normalized total forecast was then compared to the weather normalized total forecast, with the difference reflecting weather effects. The difference was then allocated, based on the rate class' weather sensitivity, to each rate class to generate the weather normalized forecast for each rate class.

Weather Sensitivity by Class

Ex 3 - Table 15 - Weather Sensitivity by Rate Class

Residential	GS<50	GS>50	SLR Connections	USL Connections
Weather Sensitivity				
92.6%	92.6%	85.3%	0.0%	0.0%

Finally, each rate class's 2011 load forecast was adjusted (reduced) by their CDM target. Kenora interpreted its 2011 total CDM target to be 1.23 GWh.

CDM Target

Kenora's 2011 load forecast reflects a CDM adjustment totalling 1.23 GWh.[11] Board staff notes that the 2011-14 Net Cumulative Energy Savings Target set for Kenora in the EB-2010-0215/0216 decision and order, dated November 12, 2010, is 5.220 GWh. The 2014 Annual Peak Demand Saving Target is 0.860 MW.

Kenora interprets the 5.220 GWh target to be the reduction target for 2014 and not, as the accumulated decreases in consumption over the 2011 to the 2014 period.[12] Kenora states that a load factor of 0.69% achieves both a 0.86 MW and a 5.220 GWh reduction in 2014. Kenora also noted that this is similar to the 68%-70% load factor outlined in the most recent 18-month outlook from the IESO. Kenora states that a 2014 GWh target of 5.22, if interpreted as cumulative, would mean that Kenora has a load factor of 0.28%. Kenora viewed this result as unreasonable.

In response to Board staff supplemental interrogatory No. 8, Kenora indicated that the IESO outlook it referenced applied to the province as a whole, and not specifically to Kenora, and that Kenora had not performed an analysis of its consumption and demand history to estimate its load factor.

Board staff submits that Kenora's calculation of the impact of CDM target achievement on its 2011 load forecast should comply with the targets as defined

[11] Source: Exhibit 3 /Tab 2 /Schedule 1 Table 16
[12] Source: Response to Board staff interrogatory No.15

and set in the Board's Decision and Order, EB-2010-0215/EB-2010-0216, dated November 12, 2010. In the Decision and Order it is clear that the MW targets refer to the "2014 Annual Peak Demand" and the GWh targets refer to "2011-2014 Net Cumulative Energy Savings".

As to what percentage of the cumulative target will be achieved in 2011, Board staff views 2011 as a start-up year for Kenora. As indicated in the response to Board staff interrogatory No. 15, the hiring details for the new Manager of CDM and Engineering were being finalized with the expectation that the position would be filled in mid- February of 2011.

Board staff calculates a 10% achievement of the GWh target to be 522,000 kWh. Accordingly, Board staff submits that the Board should increase Kenora's proposed kWh load forecast by 0.708 GWh.[13]

Except for the customer forecast component (and CDM target), Board staff has no other concerns with respect to Kenora's Load Forecast.

OTHER DISTRIBUTION REVENUE

Kenora generates other distribution revenue which offsets Kenora's Service Revenue Requirement. Other distribution revenue is comprised of Specific Service Charges, Late Payment Charges, Other Distribution Revenues and Other Income and Expenses. Specifics include revenue and income related to providing street lighting maintenance services to the City of Kenora ("city"), sewer and water billing services for the city, interest on variance & deferral account balances, investment interest, electric property rental, retail services and gains on asset sales.

Historical and proposed Other Distribution Revenues, which are an offset to the Service Revenue Requirement, are set out in the table below.

[13] Calculation: 1.23GWh less 0.522GWh.

Other Distribution Revenue	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Specific Service Charges	$ 73,608	$ 38,232	$ 37,393	$ 36,650	$ 37,040	$ 37,000	$ 37,000
Late Payment charges	$ 22,142	$ 23,524	$ 30,609	$ 31,710	$ 42,618	$ 43,000	$ 43,000
Other Distributing Revenues	$ 130,446	$ 124,147	$ 110,598	$ 112,040	$ 116,333	$ 159,790	$ 161,040
Other Income and Expenses	$ 141,393	$ 123,757	$ 169,313	$ 146,012	$ 109,021	$ 78,375	$ 112,166
TOTAL	$ 367,589	$ 309,660	$ 347,913	$ 326,412	$ 305,012	$ 318,165	$ 353,206
year-on-year % change		-15.8%	12.4%	-6.2%	-6.6%	4.3%	11.0%
Adjustmentment for 2011 Rev. Req.Offset							
-less 1/2 of $20k gain on sale of bucket truck							-$ 10,000
- plus $0.25 Retailer Administration Fee							$ 14,040
Revenue Requirement Offset							**$ 357,246**

Board staff has a concern with proposed 50-50% sharing between the shareholder and the ratepayer of the anticipated gain of $20,000 stemming from the sale of the bucket truck in 2011. Kenora sees this treatment as consistent with the guidelines contained in the 2006 Rate Handbook. In response to Board staff supplemental interrogatory No. 5, Kenora agreed that the rate setting exercise set out in the 2006 Handbook focused on actual results for 2004 and 2005 and not on the proposed budget for the test year.

Board staff questions whether the treatment described in the 2006 Handbook applies in a forward looking cost of service context. The sale of the existing truck and the $150,000 purchase of the replacement truck are planned events, yet to occur. Given the bill impacts that result from the proposed test year revenue requirements, attributing 100% of the gain to the benefit of rate-payers would help in mitigating the bill impact level. The question to consider is whether there is a sound reason for ratepayers to share the gain on a planned sale of an existing truck with the shareholder while solely the ratepayer bears the costs of the purchase of the replacement truck. Board staff submits that the 50-50% gain sharing treatment contained in the 2006 Handbook does not necessarily apply in this situation since the replacement, and corresponding sale, is part of the Applicant's capital expenditure proposals for the prospective test year. The truck to be sold cannot be considered surplus because it is being replaced with another.

Kenora is also proposing to add a specific service charge, "Service Disconnection Fee - if requested by customer" to the standard Schedule of Rates and Tariffs.[14] Kenora proposes that the fee be the same as the standard disconnect/reconnect rates for non-payment set out in Kenora's schedule of rates and tariffs. Kenora notes that it is a service identified in Kenora's Conditions of Service and that

[14] Response to Board staff interrogatory No. 4

associated revenues have been included in the other distribution revenues presented in the evidence at Exhibit 3 Table 21.

Board staff has no concerns with this proposal.

RATE BASE

Kenora is requesting approval of $10,307,488 for its 2011 rate base. Year-on year actual increases have averaged between 7% and 9% while 2011 is forecasted to be 18% higher than the 2010 budget. Excluding the Working Capital Allowance ("WCA"), the increase over 2010 is 21.7%. The historical and forecasted rate bases are summarized in the table below.

Rate Base	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Gross Fixed Assets	$ 10,350,001	$ 9,920,236	$ 11,075,009	$ 11,700,105	$ 13,176,501	$ 14,236,501	$ 16,551,169
Accumulated Depreciation	$ 5,268,684	$ 4,989,543	$ 5,429,740	$ 5,830,549	$ 6,318,924	$ 6,838,758	$ 7,503,174
Net Book Value	$ 5,081,317	$ 4,930,693	$ 5,645,269	$ 5,869,556	$ 6,857,577	$ 7,397,743	$ 9,047,995
Average Book Value	$ 5,044,136	$ 4,968,823	$ 5,287,981	$ 5,757,413	$ 6,363,567	$ 7,127,660	$ 8,672,540
Working Capital	$ 8,297,396	$ 8,414,879	$ 9,214,721	$ 9,216,896	$ 9,597,244	$ 10,699,634	$ 10,899,652
Working Capital Allowance (WCA)	$ 1,244,609	$ 1,262,232	$ 1,382,208	$ 1,382,534	$ 1,439,587	$ 1,604,945	$ 1,634,948
Rate Base	$ 6,325,927	$ 6,231,055	$ 6,670,189	$ 7,139,947	$ 7,803,153	$ 8,732,605	$ 10,307,488
rate base year-on year inc.	na	-1.5%	7.0%	7.0%	9.3%	11.9%	18.0%
rate base (excl. WCA) year on year inc.		-1.5%	6.4%	8.9%	10.5%	12.0%	21.7%

The significant increase in 2011 in excess of the historical average is largely due to the inclusion of Smart Meter costs of $894,178 (gross plant of $1,024,635 less accumulated depreciation of $130,457).[15] Board staff will address this topic later in the submission.

Board staff takes no issue with Kenora's methodology (15% of specified amounts) for calculating the WCA.

Board staff submits that Kenora should update the WCA to reflect any changes in controllable expenses and load forecasts as determined by the Board in its Decision, the most current estimate of the RPP commodity price and updates to reflect current retail transmission prices. In the prefiled evidence, Kenora used a commodity price of $0.065/kwh for both RPP and Non-RPP consumption. Board staff notes that the latest (Nov. 1, 2010) commodity RPP is different from the price Kenora used and that the May 1, 2011 prices will be issued in April. Board staff

[15] Source: Exhibit 9-2-3 p.2 table10

submits that Kenora should provide a revised WCA to reflect any updated commodity prices and/or retail transmission rates announced prior to the filing date of the reply submission or, if necessary, the draft rate order. The material should provide sufficient detail and discussion to aid other parties in understanding the numbers provided and their derivation.

CAPITAL EXPENDITURES

The following table summarizes Kenora's historical and proposed capital expenditures as presented in the pre-filed evidence. In support of its proposed expenditures, Kenora filed an Asset Management Plan.

Capital Expenditures	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Transformer Station Equip >50 kV (note1)	$ 47,250	$ 819,137	$ 351,639	$ 1,059,614	$ 280,000	$ 605,000
Poles, Towers & Fixtures	146,380	101,207	131,453	35,886	67,000	60,000
O/H Conductors & Devices	69,718	77,375	92,308	98,347	75,000	100,000
Underground Conduit	-	383			62,000	18,000
U/G Conductors & Devices	4,092	53,107	5,040		90,000	40,000
Line Transformers	32,498	26,796	32,311	31,459	97,000	119,000
Services	63,205	50,173	26,568	33,914	33,000	35,000
Meters	6,645	37,648	537	469	3,000	3,500
Buidling & Fixtures	1,859				365,000	155,000
Office Furniture and Equipment	2,911	2,147	509	7,284	1,000	16,000
Computer Equipment - Hardware	9,176	1,855	538	2,194	6,000	2,000
Computer Equipment- Software	-		3,192	12,094	2,000	2,000
Transportation	-	25,556		247,161		150,000
Tools, Shop & Garage	3,040	1,408	4,442	2,861	5,000	5,000
Measure & Test Equip	3,738		377		2,000	2,000
Communication Equipment			378			
Miscellaneous Equipment	-	13,484			2,000	2,000
Capital Contribution	-46,120	-55,504	-24,196	-54,891	-30,000	-30,000
TOTAL	$ 344,392	$ 1,154,772	$ 625,096	$ 1,476,392	$ 1,060,000	$ 1,284,500

note 1: Transformer Station expenditure in 2007 includes T3 replacement due to lightning strike. Insurance claim posted in 2008 for $422,303 and in 2009 for $163,210

With respect to the capital expenditures incurred between 2006 and 2009, Board staff is of the view that the expenditures have been adequately explained by the Applicant. In response to VECC interrogatories No. 9 and No. 37, Kenora indicated that its preliminary 2010 actuals total $860,138, excluding accruals, and that accruals would be established by March 28, 2011.

In the event that Kenora includes the accruals and confirms its 2010 actuals in its reply submission, Board staff submits that this update, regardless of whether it is higher or lower, should not replace the current number, i.e. a 2010 budgeted capital expenditure of $1,060,000. The $1,060,000 is reflected in the 2011 proposed rate base. Replacing the $1,060,000 with an updated number would be without evidentiary foundation since the updated number would not have been examined in this proceeding.

There are four projects or items which account for the inter-year volatility in annual capital expenditures: the Transformer Station rebuild program, a double bucket truck replacement in 2009, building repair and replacement in 2010 and 2011 and a single bucket truck replacement in 2011.

The most significant of these is the rebuild/replace program affecting Kenora's three Transformers (> 50kV).

The transformer history and plan is as follows:

- Transformer T2: struck by lightning in 2007 and replaced with a used unit from the U.S.;
- Transformer T3: failed in 2009 and has been replaced with the rebuilt T2;
- Transformer T1: will be replaced in 2011 with the rebuilt T3;
- Spare: the replaced T1 will be rebuilt and serve as a spare.

In response to Board staff supplemental interrogatory No. 2, Kenora confirmed that (i) T1 remains in service and will be replaced with the rebuilt T3 unit currently on site during the first week of June 2011, and (ii) T1 has not yet been rebuilt and that the rebuilt T1 will be refurbished and on-site to serve as a spare by the end of 2011.

Board staff submits that Kenora consider deferring the inclusion of the re-build costs of the spare transformer into rate base. This would limit the significant growth in 2011 rate base and help mitigate the bill impact on Kenora's customers of the applied for rates in this proceeding. Board staff notes that the projected future capital expenditures, at $848,888 for 2012, $429,000 for 2013, and $329,000 for 2014 are significantly less than 2010 and 2011 levels.[16] Board staff notes that Kenora in response to Board staff interrogatory No. 13 stated that the T1 unit should be completed in 2011 for system reliability reasons. As long as T1 is not rebuilt, there is no spare in the event of a failure in the other units. A failure would result in emergency replacement costs.

Kenora also in response to Board staff interrogatory No. 13 identified a number of

[16] Source: Exhibit 2-3-2 Table 18.

capital projects, amounting to $39,500 which reflect a reduction or deferral to 2012, and an anticipated increase of $34,000 in capital contributions. Board staff submits that these adjustments should be accepted by the Board.[17]

OPERATING COSTS

Kenora 's historic and projected operating costs include Operating, Maintenance and Administration ("OM&A), Depreciation and Federal and Provincial ("PILS") taxes. These figures are provided below.

OPERATING EXPENSES	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
OM&A	$ 1,414,783	$ 1,278,734	$ 1,387,191	$ 1,633,819	$ 1,701,608	$ 1,800,457	$ 2,062,785
Amtz/Depreciation	$ 349,626	$ 367,748	$ 394,996	$ 379,434	$ 436,107	$ 480,640	$ 468,960
Property Taxes	$ 12,668	$ 12,668	$ 12,397	$ 12,684	$ 12,478	$ 13,000	$ 13,260
Federal/Provincial Taxes	$ 1,917	$ 7,561	$ 11,203	$ 2,808	$ 2,269	$ -	$ 20,812
TOTAL	$ 1,778,994	$ 1,666,711	$ 1,805,787	$ 2,028,745	$ 2,152,462	$ 2,294,097	$ 2,565,817

Operating, Maintenance and Administration

Kenora proposed a Test Year budget of $2,062,785[18] which represents a 14.6% increase over 2010 and a 45.8%, or 7.8% annual, increase over 2006 Board approved. Historical and proposed OM&A expenditures are presented in the table below.

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Operation	$ 117,762	$ 119,291	$ 132,133	$ 139,373	$ 172,747	$ 172,173	$ 198,090
Maintenance	$ 427,306	$ 269,662	$ 245,439	$ 303,518	$ 373,025	$ 365,813	$ 400,649
Billing & Collection	$ 375,827	$ 354,924	$ 387,712	$ 411,372	$ 490,429	$ 560,760	$ 576,943
Community Relations	$ 1,370	$ 972	$ 4,432	$ 98,291	$ 2,261	$ -	$ -
Administrative & General *	$ 492,518	$ 533,885	$ 617,474	$ 681,265	$ 663,146	$ 701,711	$ 887,103
Total	**$ 1,414,783**	**$ 1,278,734**	**$ 1,387,190**	**$ 1,633,819**	**$ 1,701,608**	**$ 1,800,457**	**$ 2,062,785**
Year on Year % Increase		**-9.6%**	**8.5%**	**17.8%**	**4.1%**	**5.8%**	**14.6%**
2011 vs 2006 Brd Approved							**45.8%**
Annual increase 2011 vs 2006 Brd Approved							**7.83%**
Annual Increase 2009 vs 2006 actual					**9.99%**		
Annual Increase 2009 vs 2006 Brd Approved					**6.35%**		
Note* excludes proporty taxes							
Source: Exhibit4 Tab1 Schedule 1 p. 2							

[17] The proposed $1,284,500 in 2011 Test Year Capital Expenditures does not reflect the $73,500 in reductions submitted by Kenora.

Kenora provided explanations for the yearly variances over the 2006 to 2009 period and noted that the inflation rates for 2006, 2007, 2008, and 2009 were 1.8%, 1.8%, 2.3% and 0.4%, respectively and for 2010 and 2011 are forecasted to be 2.0% annually.

As compared to 2006 Board Approved, the significant increases in total OM&A appear to start in 2007. Using the information on the record, Board staff calculated that the items listed in the table below account for the increase in 2011 as compared to 2007 actual.

Items: increase between 2007 and 2011	(in k$)
Inflation @ 6.8%	$ 140
Full year cost of apprentice linesman hired in 2007	$ 40
Regulatory ($150k for 2011 case amortized over 4 yrs.)	$ 37
Asset Managemnt Plan Development & Completion*	$ 37
Smart Metering expensed to OM&A	$ 60
Engineer in 2010 (CDM/GEA/Smart Grid) - Kenora share	$ 40
Two (2) new office staff in 2009	$ 110
One (1) new management staff in 2010	$ 100
Overhead Conductor & Devices Maintenance	$ 75
Miscl.	$ 37
TOTAL	$ 676
*note: $150k over 4 years	

Board staff submits that Kenora in its reply submission may wish to comment on whether this is an accurate list of the drivers responsible for the increase between 2007 and 2011.

<u>Increase between 2010 and 2011</u>

Kenora's OM&A increases by 14.6% or $262,312 between 2010 and 2011. Based on the evidence on the record, Board staff has identified the major reasons for the increase in the following table.

Increase in OM&A Between 2010 and 2011		
Full year compensation for employee who returned to work in August 2010	$	63,000
3% increase in wages and salaries	$	31,600
Full year compensation for CDM manager hired in late 2010	$	31,000
General non-compensation inflation @ 2% (approximate)	$	15,000
2011 COS Application Regulatory Costs (1/4 of $150,000)	$	37,500
Asset Management Plan Development and Completion (1/4 of $150,000)	$	37,500
OM&A Contra Account -5695 (2010 Smart Meters charged to D/V account)	$	60,000
Net Miscl decreases, increases	-$	13,288
TOTAL	$	262,312
source: Exhibit 4-2- 2,3,4		

Board staff notes that Kenora indicated that costs, included in the test year revenue requirement, for the CDM Manager/Engineer hired in 2010 pertain to non-CDM activities

Compensation

Kenora indicated that the 2011 OM&A includes about $32,000 for unionized and management salary and wage increases of 3%. The last year of the existing union contract, April 1, 2010 to March 31, 2011, provides a 3% increase. Kenora has assumed a 3% increase for the future contract. Board staff submits that salary and wage increases for all employees in the current economic environment should be limited to no more than 1.3% which is the price escalator the Board is using in the 2011 IRM proceedings.

OMERS

In response to Board staff supplemental interrogatory No. 22, Kenora indicated that it did not include the impact of the increase in contribution rates recently announced by OMERS for 2011, 2012, and 2013. Kenora calculates the amount to be $1,167.00 for 2011. Board staff agrees with Kenora that it should be included in the approved revenue requirement. Board staff asks that in its reply submission Kenora confirm whether any of the $1,167.00 is capitalized and if so, what portion.

Regulatory Cost

In its filed evidence Kenora forecast that it would incur $150,000 related to the 2011 COS application and proposed to amortize $37,550 annually in OM&A over 4 years commencing in 2011. The table below breaks out the $150,000 into its major elements.

Ex 4 - Table 7 - Regulatory Costs

Regulatory Cost Category	Ongoing / One-Time Cost	Last Rebasing Year	Last Year of Actuals	Bridge Year	% Change Bridge vs Last Year Actuals	Test Year Forecast	% Change Test Year vs Bridge Year
1. OEB Annual Assesment	Ongoing	12,148	13,497	14,940	11%	16,540	11%
2. OEB Hearing Assessments (application inititated)	Ongoing					38,000	
3. OEB Section 30 Costs (OEB intitiated)	Ongoing	480	638	750	18%	1,000	33%
4. Expert Witness Cost	One-Time					6,000	100%
5. Legal Costs for Regulatory Matters	Ongoing			3,000	100%	15,000	400%
6. Consultants Costs for Regulatory Matters	Ongoing		878	32,000	100%	55,000	72%
7. Operating Expense associated with staff Resources Allocated to Regulatory Matters	Ongoing		3,000	45,000	1400%	30,000	-33%
8. Operating Expenses associated with other resources	Ongoing						
Total Regulatory Costs Included in Rate Application						**150,000**	

In response to Board staff interrogatory No. 23, Kenora indicated that it would be willing to update its estimate of total OEB and intervenor costs, if the Board could provide such information.

In response to VECC interrogatory No. 42, based on the hearing process set out in Procedural Order No. 1 Kenora restated its 2011 COS regulatory costs as follows:

Estimated COS Rate Application Regulatory Costs

Regulatory Cost Category	Amount
Total Intervenor Costs - 2011	12,000
OEB Costs for COS Rate Application - 2011	30,000
Consultants Costs for COS Rate Application - 2010	8,787
Consultants Costs for COS Rate Application - 2011	15,000
Total Regulatory Costs to complete Rate Application	**65,787**

On this basis, Kenora indicated that the amount amortized annually now equates to $16,447. Accordingly the provision for 2011 OM&A would be reduced by $21,053 (the difference between $16,447and $37,550).

Board staff submits that the total regulatory costs for this proceeding can be reduced by at least a further $7,000, assuming that the $30,000 for "OEB Costs for COS Rate Application-2011" is for the Board's Section 30 costs. Given that this proceeding is written, with no oral component, Board staff anticipates that Section 30 costs will not exceed $2,000.[19]

Affiliate Charges

Kenora performs water/sewer meter readings and billing functions for the City of Kenora ("city"). Kenora bills the city by the number of water meters read monthly, based on an analysis of the actual staff and vehicle costs to Kenora for those services. [20] Billing services are billed to the city, based on annual water customer count billed and the actual payroll costs to Kenora for the billing clerk. Kenora also performs streetlight maintenance for the city. For streetlight maintenance, actual costs including labour, labour burden, stores material, along with vehicle costs are charged and include a 20% mark up. Revenues from these services are recorded in Other Revenues account number 4375.

For the 2011 Test Year, the city charges Kenora $224,110 for services and Kenora charges the city $169, 415 for services. [21]

Board staff has no concerns on the costs and revenues associated with the transactions between Kenora, given the corrections identified by Kenora in its response to Board staff interrogatory No. 24. Board staff is not commenting on whether these activities are compliant with Section 71 of the *Ontario Energy Board Act.*

Amortization and Depreciation

Board staff does not have any concerns with the amortization/depreciation amounts proposed by Kenora. In the event the Board make changes to Kenora's capital expenditures, Board staff submits that the Board in its decision should direct Kenora to reflect the impact on amortization/depreciation in its draft rate order.

Income Taxes

[19] Calculation : OEB costs of $30k less expected amount of $2k and divided by 4

[20] Source: Exhibit 4-2-5

[21] Exhibit 4-2-5 p2 table 8 and the correction per the response to Board staff interrogatory No. 24. The correction reduces OM&A costs by $40,434.

Board staff has no concerns with the income tax calculations provided by the Applicant.

COST OF CAPITAL

Kenora is proposing a test year weighted cost of capital of 6.23% based on a deemed capital structure which is consistent with the Board's guidelines.

2011 Test Year Cost of Capital					
	Amount (Rate Base)	Weight	Cost Rate	Weighted Cost	Return
Long Term Debt	$ 5,772,193	56%	3.95%	2.21%	$ 228,002
Short Term Debt	$ 412,300	4%	2.07%	0.08%	$ 8,535
Total Debt	$ 6,184,493	60%			$ 236,536
Common Equity	$ 4,122,995	40%	9.85%	3.94%	$ 406,115
TOTAL	$ 10,307,488	104%		6.23%	$ 642,651

Source: Exhibit 5-1-2 table 1

Board staff notes that the cost for Short term Debt and ROE reflected in the table above are the same as the cost of capital parameters approved by the Board for 2010 rates.[22] Kenora's is proposing a long term debt rate debt rate of 3.95%. Kenora identified the following (see table below) debt issues/loans from the city and Infrastructure Ontario as comprising the instruments used to calculate its long term debt. In aggregate, these instruments total $5,197,479 and carry interest costs of about $205,000.

[22] Cost of Capital Parameters for 2010 issued on February 24, 2010

Cost of Debt	Amount	Issue Date	Rate	Interest
City of Kenora Loan	**$ 3,069,279**	1-Jan-00	**2.77%**	**$ 85,019**
Infrastructure Ontario Loans				
Substation re-build	$ 700,000	1-Sep-10	5.80%	$ 40,600
Smart Meter	$ 1,128,200	Sept 09/Sept /10	5.50%	$ 62,051
Substation re-build	$ 300,000	1-Jan-11	5.80%	$ 17,400
Sub-total	**$ 2,128,200**			**$ 120,051**
Grand Total	**$ 5,197,479**		**3.95%**	**$ 205,070**

Source: Exhibit 5-1-2-p.2 table 2

Subject to Board staff's comments below on the quantum of the debt instruments, Board staff notes that the instruments total $5,197,479 while the 2011 rate base capitalized by long term debt totals $5,772,193. Board staff notes that Kenora has chosen to apply its embedded debt rate to plug the difference of $574,714 as opposed to using a forecast or the Board's deemed debt rate. Board staff supports this approach as it is consistent with prior Board decisions where there is no debt forecasted to be issued.

Updated Infrastructure Ontario Financing Plans

In response to VECC interrogatory No. 21, Kenora provided (see table below) updated interest carrying costs to reflect the current status, of the anticipated conversion, from loan to debenture, of the borrowings from Infrastructure Ontario.

Substation Rebuild L	Infrastructure Ontario	N	October 1, 2010	400,000	40	1.50%	2011	6,000
Smart Meter Loan	Infrastructure Ontario	N	Dec/09	900,000	15	3.50%	2011	31,500
Shareholder Loan	City of Kenora	Y	January 1, 2000	3,069,279	40	2.77%	2011	85,000
Smart Meter Loan	Infrastructure Ontario	N	June 1, 2011	228,200	40	5.50%	2011	6,275
Substation Rebuild L	Infrastructure Ontario	N	June 1, 2011	200,000	40	1.50%	2011	1,500
						TOTAL		$130,275

The updated interest now totals $130,275 due to delays in the conversion. Excluding the interest on the city loan, the Infrastructure Ontario interest totals $42,245 as compared to the $120,051 as found in the pre-filed evidence.

Board staff notes that the instruments shown in the table above total $4,797,000 which is $400,000 less than the debt total of $5,197,479 identified in Exhibit 5-1-2 table 2. Board staff submits that Kenora should identify the other debt instruments that make up this difference in its reply submission.

Kenora has indicated that it is ready to update its capital cost calculations to align them with the applicable Board approved cost of capital parameters. Board staff supports this approach and submits that the Board in its decision direct Kenora to reflect in its draft rate order the applicable cost of capital parameters issued by the Board on March 3, 2011.

<u>City of Kenora Loan</u>
Board staff notes that in the amendments to the agreement re: the city bylaws concerning the $3,069,278 loan with the city, Section 7 of the original bylaw was amended as follows:

> 5. Section 7 shall be amended to read as follows:
>
> On December 31, 1999, the Company shall borrow $3,069,278.85 by way of debenture from the City. This debenture shall be repayable based on demand, and shall bear interest at a rate equal to the City's appointed bank's prime rate for that month as used for calculating interest payments on the City's accounts.

Board staff is concerned with the variability risk for Kenora inherent in the terms of this debenture. For example, the debenture can be recalled at any time and carrying costs could increase significantly in times of increasing short term interest rates. Board staff questions the appropriateness of the existing terms and conditions and has concerns over how this will affect Kenora's asset management and operations planning. Board staff submits that Kenora should develop plans in the near future that would mitigate any financial distress that could potentially ensue.

COST ALLOCATION AND RATE DESIGN

Loss Factors

Kenora 's average (2005-2009) total loss factor equates to 1.0413 and reflects a distribution loss factor of 1.0368 and the pre-established supply loss factor of 1.0413. In that this is very close to the currently approved loss factor of 1.0430, Kenora proposes to leave it at 1.0430.[23]

[23] For the Total Loss Factor- Secondary Metered Customer < 5,000 kW. The proposed factor for Primary Metered Customer < 5,000kW is 1.0325

TOTAL LOSS FACTOR	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	Average
Distributon Loss Factor	1.0537	1.0352	1.0366	1.0393	1.0192	1.0368
Supply Faciltiy Loss Factor at 1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.045
TOTAL	1.0582	1.0397	1.0411	1.0438	1.0237	1.0413

In interrogatory No.34 Board staff noted that the 2009 actual Distribution Loss factor, at 1.0192 was significantly lower than prior years experience. Kenora responded that the 2009 result is likely due to a calculation anomaly because of the unbilled kWh at each year end. Kenora provided factors based on billed consumption matched to IESO purchases. These factors do not show a material decline for 2009. Board staff accepts Kenora's explanation and has no concerns with the proposed loss factor.

Revenue to Cost Ratios

Kenora's proposed Revenue to Cost ratios for 2011, 2012 and 2013 are set out in the table below.

Ex 7 - Table 4 - Proposed Revenue to Cost Ratios

Class	Proposed Revenue to Cost Ratios			Policy Range
	2011	2012	2013	
Residential	100.67%	100.67%	100.67%	85 - 115
GS <50 kW	80.00%	80.00%	80.00%	80 - 120
GS >50 kW	124.52%	124.50%	124.58%	80 - 180
Streetlight	77.66%	77.66%	77.66%	70 - 120
USL	138.00%	129.00%	120.00%	80 - 120

Kenora's proposed ratios fall within the Board's recommended ranges with the exception of un-metered scattered load which comes into range only in 2013.

Kenora indicated, with respect to the GS <50kW, GS > 50kW and unmetered scattered load classes that it has aligned rates in the band beyond the level indicated by the Cost Allocation model to reduce the amount of interclass subsidization. The comparative ratios for 2011 are shown in the table below.[24]

[24] "Status Quo Ratios" in the table refer to results of the Updated Cost Allocation.

Ex 7 - Table 5 - Rebalancing Revenue-to-Cost Ratios

Class	Previously Approved Ratios 2006 CA Model	Status Quo Ratios	Proposed Ratios
Residential	103.87%	100.68%	100.67%
GS <50 kW	81.23%	76.60%	80.00%
GS >50 kW	125.38%	128.44%	124.52%
Streetlight	56.19%	77.58%	77.66%
USL	42.85%	156.72%	138.00%

Board staff notes that the proposed ratio for unmetered scattered load represents a phase in period of three years to bring the ratio within range.

Board staff has no concerns with Kenora's proposed ratios.

Monthly Fixed Charges and Variable Distribution Rates

Kenora's current and proposed fixed monthly and variable distribution rates are presented in the table below.

Change in Rates				
	Fixed Monthly		Variable	
	Current	Proposed	Current	Proposed
Residential	$ 13.53	$ 19.86	$ 0.0099	$ 0.0145
GS < 50kW	$ 25.77	$ 39.79	$ 0.0040	$ 0.0062
GS > 50kW	$ 372.26	$ 528.38	$ 1.2372	$ 1.6794
Streetlighting (kW)	$ 3.54	$ 5.20	$ 2.3277	$ 3.4214
Unmetered Scattered Load	$ 13.00	$ 16.65	$ 0.0041	$ 0.0053

Kenora indicated that its proposed fixed monthly rates are consistent with the Board's guidance found in the *Board Report on the Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), dated November 28, 2007. The proposed monthly fixed rates are above the floor amount (i.e. calculated as avoided costs). Kenora's understanding of the current regulatory status is that distributors are not required, for the time being, to make changes to their monthly fixed rate as it pertains to exceeding the ceiling. In response to VECC IR No. 24, Kenora provided a history of the Board's activity concerning the question of fixed/variable split and the Board's communication, in October 2010, to conclude the Review of Distribution Revenue Decoupling Mechanisms. In light of this, Kenora indicated it would be imprudent to make adjustments to the variable/fixed split before further the fixed/variable split issue is resolved.

The table below presents the current and proposed revenue requirement allocations between the fixed and variable components that Kenora used to calculate the proposed rates.

Ex 8 - Table 5 - Current and Proposed Allocation of Base Revenue Requirement

Rate Classification	Current Fixed Revenue Proportion	Current Variable Revenue Proportion	Proposed Fixed Revenue Proportion	Proposed Variable Revenue Proportion
Residential	66.71%	33.29%	66.75%	33.25%
General Service Less than 50 kW	67.05%	32.95%	70.85%	29.15%
General Service Greater than 50 kW	69.13%	30.87%	73.06%	30.23%
Streetlights	67.58%	32.42%	63.63%	36.37%
Unmetered Scattered Load	38.13%	61.87%	88.72%	11.28%

Board staff does not have any concerns with Kenora's proposed fixed monthly rates.

RETAIL TRANSMISSION SERVICE RATES

Kenora is proposing to revise its Network Service and Line and Transformation Connection rates, pursuant to the Board's guidelines for electricity distribution Retail Transmission Service rates (G-2008-0001) Revision 2.0 dated July 8, 2010. The proposed rates found in the pre-filed evidence are between 6.3% and 7.3 % lower than the existing RTSR rates.

Kenora noted that it would be prepared to adjust these rates, should the UTR rates change early in 2011.

Board staff notes that on January 18, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2010-0002) which adjusted the UTRs effective January 1, 2011. The new UTRs are shown in the following table:

Uniform Transmission Rates	kW Monthly Rates		Change
	Jan 1, 2010	Jan 1, 2011	
Network Service Rate	$2.97	$3.22	+8.4%
Connection Service Rates			
Line Connection Service Rate	$0.73	$0.79	
Transformation Connection Service Rate	$1.71	$1.77	
			+4.9%

Board staff submits that Kenora update its proposed RTSR rates reflecting these new rates and that Kenora include this information, along with the completed RTSR module, in its reply submission.

SMART METERS

Kenora indicated that its residential and small commercial installations in total were 92% completed by the end of 2009 (4624 residential and 465 small commercial) and expected 100% installation by the end of 2010.[25] Kenora noted that smart meter costs were audited as part of the 2009 financial statement audit.

Kenora is seeking a number of approvals regarding the smart meter program, including:

- An actual cost recovery rate rider of $2.09 per metered customer per month for the period May 1, 2011 to April 30, 2012. This rate rider will collect the difference between the smart meter adder collected from May 1, 2006 to December 31, 2009 and the 2009 and 2010 revenue requirement related to smart meters deployed as of December 31, 2009.

- Approval to include smart meter capital deployed as of December 31, 2009 in the 2011 rate base, in the amount of $894,178, that supports the 2011 revenue requirement and distribution rates, which is the subject of this rate application.

- Approval to include smart meter operation and maintenance expenses of $59,000 in the 2011 revenue requirement associated with smart meters deployed as of December 31, 2009.

- A reduction in the current smart meter funding adder, from $1.00 to $0.09 per month per metered customer, to fund remaining smart meter capital

[25] In response to VECC interrogatory No. 31 VECC indicated that as of December 31, 2010 (as reported to the Board on January 11, 2011), 100% of the residential and 97.9% of the GS< 50kW installations are completed -16 meters remained to be installed.

expenditures for 2010 and 2011 to complete the Smart Meter capital program.

Rate Rider - Recovery of Smart Meter Costs

Kenora 's evidence included the information described on page 11 of the Board's Smart Meter Guidelines, that should accompany a request for the recovery of smart meter costs.[26] The Board noted in its 2010 IRM Decision and Order for Kenora, EB-2009-0200, that Kenora is authorized to conduct smart meter activities because it is identified in paragraph 8 of section 1(1) of O. Reg. 427/06.

Kenora indicated that it has been a member of the North West Utilities Smart Meter Initiatives Group for this project. Board staff submits that Kenora should include, in its reply submission, a copy of the agreement under which smart meter assets have been procured in order to complete the record.

Kenora's per unit costs for smart meters and collectors appear in the table below.

Smart Meter Per Unit Costs

Ex 9 - Table 6 - Smart Meter Per Unit Costs

Advanced Metering Collection Device - Residential and GS<50		Cost Per Meter
Costs	2009	
Total Capital Cost Installed Meter	$902,185	
Number of Meters Installed	5,097	$177

OM&A Costs		Cost Per Meter
Costs	2009	
Incremental OM&A Costs -2009 Actual	$119,548	$23
OM&A Costs		Cost Per Meter
Costs	2010	
Incremental OM&A Costs - 2010 Projected	$60,000	$12

[26] Smart Meter Funding and Cost Recovery G-2008-0002 (dated October 22, 2008) p.11

- a copy of the agreement(s) under which the smart meter assets have been procured
- calculation of the revenue requirement related to smart meter costs
- capital and operating unit cost per installed smart meter and in total for:
    - procurement and installation of the components of the AMI system
    - customer information system
    - incremental operating and maintenance activities
    - changes to ancillary systems
    - stranded meters
- a variance analysis comparing actual costs to previously filed costs
- justification for any smart meter or AMI costs incurred to support functionality that exceeds the minimum functionality adopted in O. Reg. 425/06
- for any costs incurred that are associated with functions for which the SME has the exclusive authority to carry out pursuant to O. Reg. 93/07, the basis on which recovery of those costs is allowed under applicable law

Board staff has no concerns with these costs in that they fall within an acceptable historical range.

Kenora is seeking approval for a new rate rider of $2.09/mo./meter, to recover the revenue requirement to December 31, 2010. Although the Smart Meter guidelines state that the recovery by way of rate rider should only consider “actuals” that have been audited[27], Kenora views the recovery of 2010 forecasted costs as beneficial for the ratepayer since this would result in interest payment savings by the utility because of improved cash flows. [28] Board staff, in principle, question Kenora’s claim of ratepayer benefit. Absent further elaboration and evidence, Board staff submits that the Board put little weight on this assertion in its findings.

Kenora noted that the incremental revenue calculation for 2008, 2009 and 2010 was based on the proposed 2011 cost of capital rates and that it will be updating them once the Board approves the cost of capital rates in this proceeding.

Board staff has a concern with the accuracy of the results from the smart meter revenue requirement model utilized by Kenora. It appears that Kenora (i) used the 2011 Cost of Capital for all years - going back to 2006 instead of the costs of capital that was explicitly or implicitly in rates in each year (ii) did not use the half year rule in 2009 for new additions ($62K instead of $68k/2) and (iii) did not calculate and include the 2010 revenue requirement for the meters installed in 2009. Board staff also notes that all the smart meter capital expenditures are recorded as Meter or Meter Installation asset type. Board staff would have expected that under Generally Accepted Accounting Principles some of the expenditures would have been recorded as Computer Hardware or Computer Software or Tools and Equipment. Board staff ask that Kenora comment on the aforementioned corrections and accordingly re-run the model. In the re-run of the model, Kenora may want to use the Board’s latest direction on cost of capital rates. [29]

[27] Per the Smart Meter Funding and Cost Recovery G-2008-0002 (dated October 22, 2008) guideline pages 11-12, utilities seeking smart meter cost recovery must base their request on costs already expensed (not forecast).

[28] Source: Response to Board staff IR No. 39.

[29] See Board letter dated March 3, 2011 re: Cost of Capital Parameters for 2011 Cost of Service Applications for Rates Effective May 1, 2011.

Rate Adder

Kenora is proposing to reduce the current smart meter funding adder, from $1.00 to $0.09 per month per metered customer, to fund remaining smart meter capital expenditures for 2010 and 2011 to complete the Smart Meter capital program.

The rate adder is based on the following forecasted 2010 and 2011 costs: annual maintenance expenses of $1,000 and installation costs in 2011 of $15,000. Board staff submits that Kenora should confirm that the installation costs pertain to the installation of meters that were purchased but not installed in 2010.

Given the relatively small magnitude of the number of meters left to be deployed, Board staff submits that the Board consider approving the inclusion of the aforementioned costs in rate base on a final basis. This will simplify the presentation of Smart Meter cost recovery on the bill and will provide finality to the smart meter review process for Kenora. Staff ask that Kenora in its reply submission indicate what the capital cost per unit costs for the remaining installations in 2011 will be as compared to the audited costs for meters already deployed.

Stranded Meters

Kenora is not seeking the recovery of the stranded meter costs by way of rate rider. The costs of the conventional, and now stranded meters, continue to be recovered in the revenue requirement since the stranded meter assets remain in rate base. Kenora referenced the Board's EB-2007-0063 decision dated August 8, 2007 to support this treatment. Kenora stated that net book value of all conventional meters was $174,069, for purchases up to December 31, 2005; that the conventional meters purchased from 2006 to 2008 had a net book value of $40,999 and these amounts are all included in rate base.[30]

Kenora also confirmed that the stranded meter costs continue to be recorded at their original cost in account 1860-Meters and are being amortized / depreciated at a 25 year rate and that it will continue with this treatment until directed otherwise by the Board. [31] A summary of the stranded costs, prepared by Kenora, appears below. [32]

[30] Exhibit 9-2-1 p.2 ln 10-15
[31] Response to Board staff interrogatory No. 38
[32] POD in the table = Proceeds on Disposition

Year	Gross Asset	Accumulated Amortization	Net Asset	POD	Contributed Capital	Residual NBV
2006	521,153	(301,507)	219,646	0	0	219,646
2007	558,801	(322,878)	235,923	0	0	235,923
2008	559,338	(344,270)	215,068	0	0	215,068
2009	559,338	(365,662)	193,676	0	0	193,676
2010 *	559,338	(387,054)	172,284	0	0	172,284

* The 2010 figures are forecast

Board staff notes that there is a difference between the amounts found in the parts i) and viii) of the response to Board staff interrogatory No. 38. i.e. (i) "net book value of all conventional meters was $174,069, for purchases up to December 31, 2005; that the conventional meters purchased from 2006 to 2008 had a net book value of $40,999" vs the total residual value of $172,284 shown in the table found in (vii)/ the table above. Board staff asks that Kenora clarify these differences especially in light of Board staff's submission, which follows, regarding the recovery of stranded meter costs.

Board staff notes that pursuant to the Smart Meter Funding and Cost Recovery Guideline (G-2008-0002), dated October 22, 2008, distributors were instructed to report the stranded meter costs in a new sub-account: Smart Meter Capital and Recovery Offset Variance Account 1555, sub-account Stranded Meter costs. Disposition of said accounts would be determined by the Board in a future proceeding.

Given that Kenora has almost completed its smart meter installation program and most of its smart meters will be included in rate base, Board staff submits that this application should also address an appropriate recovery mechanism for recovering the stranded costs.

Kenora proposes to retain the costs in rate base. As Kenora noted, in its combined decision[33], the Board indicated that stranded meter costs should remain in rate base. However, the combined decision was issued several years ago at a time when the deployment of smart meters was only at an early stage and the full impacts of the stranded meter costs were largely unknown. In the current situation, as the distributor will be receiving rate base treatment on most of its smart meters

[33] Decision, EB-2007-0063, p.16

that have replaced its “stranded” meters, Board staff submits that it may no longer be appropriate for the distributor to receive a concurrent rate base treatment for stranded meters that are no longer used and useful.

Board staff submits that at this time, a simpler and more appropriate approach from an accounting perspective for recovery of stranded meters may be to allow recovery of the estimated residual net book value of the overall stranded meters. The estimated amount should comprise the pooled residual net book value of the removed from service meters, less any sale proceeds and contributed capital, to the time when smart meters would have been fully deployed (e.g., as of December 31, 2011). The total estimated stranded costs of $175,000 as of December 31, 2011 could be allowed to be recovered through a separate rate rider. If this proposal is adopted by the Board, Kenora should revise this estimate to the end of 2011 to reflect the derivation of the amount discussed above and to reflect information that is more current. Kenora may wish to suggest a recovery period. Board staff also submits that the estimated total costs related to the stranded meters in rate base on approval for recovery be removed from rate base (and Account 1860, Meters) and tracked in “Sub-account Stranded Meter Costs” of Account 1555. The associated recoveries from the separate rate rider should also be recorded in this sub-account to draw down the balance in the sub-account. The approved estimate of stranded meter costs should be trued-up to actual costs, recorded in the sub-account, and submitted for review in the distributor’s next cost of service application. A final disposition of the sub-account balance (comprised of the final stranded meter costs as of December 31, 2011 net of the rate rider recoveries) would be addressed in that proceeding.

Board staff invites parties to comment on the recovery methodology for the stranded meter costs, the proposed recovery period, and the associated bill impacts.

DEFERRAL AND VARIANCE ACCOUNTS

Kenora provided a listing of the Deferral and Variance accounts currently in use, the balances, including interest, as of December 31, 2009, and the account balances proposed for disposition. [34]

The amount proposed for disposition totals $518,855 (credit). The total for all

[34] Exhibit 9-1-1 table 1 and table 2

accounts excluding the global adjustment sub-account is $674,716 (credit) and the global adjustment sub-account balance is $155,561 (debit). A break-out is presented in the table below. [35]

DEFERRAL AND VARIANCE ACCOUNTS - Proposed for dispostion-		
(balances, including interest, as of 31-12-2009 **Balances for Dispostion**	Account Number	Amount
RSVA - Wholesale Market Service	1580	-$ 331,676
RSVA - RT Network Service	1584	-$ 6,836
RSVA - RT- Connection	1586	-$ 507,032
RSVA - Power including global adjustment	1588	$ 246,112
Sub-total RSVA accounts		-$ 599,432
Other Regulatory Assets *	1508 & 1525	$ 80,577
Total **		-$ 518,855

note: * OEB cost assessments & OMERS
** totals $521,517 including interest to April 30, 2011

Kenora also indicated that account balances totalling $671,887 will remain on the books and are not proposed for disposition by rate rider in this proceeding. A break-out of the $671,887 is presented in the table below.[36]

[35] In response to Board staff interrogatory No. 31, Kenora confirmed that the account balances set out in Exhibit 9-1-1-p.1 table 1 are consistent with the balances reported under RRR 2.1.7 for the year ended December 31, 2009.

[36] The table, extracted from Kenora's evidence, includes Smart Meter related balances. Kenora is proposing to close the Smart Meter balances to rate base. Accordingly, recovery will be through the revenue requirement and not by way of rate rider. Kenora is not proposing to recover any of the other balances.

DEFFERAL AND VARIANCE ACCOUNTS	Balances not cleared by rate rider
(balances, including interest, as of 31-12-2009)	
	Amount
IFRS Transition	$ 3,734
Renewable Generation	$ 12,438
Smart Grid	$ 1,847
Smart Meters - Revenue and Capital	$ 869,938
Smart Meters - Expenses	$ 138,217
Regulatory Asset Recovery	$ 1,367
PILs account 1562	$ 6,535
Future Income Tax Accrual	-$ 362,189
Total	**$ 671,887**

Staff also notes that Kenora has the ability to dispose of the global adjustment sub-account only to non-RPP customers and Kenora should continue this practice for this application including charging the subject rider on the delivery portion of the bill.

Kenora, while noting the default term for the disposition of the group 1 balances is usually one year, proposed to recover the credit balance of $521,517 over a four year period. Kenora was concerned that a disposition period of one year for the credit would result in a significant rate impact commencing May 1, 2012 when the credit rate rider would lapse. Kenora saw a four year term as a way to mitigate the resulting rate shock associated with a one year disposition.

In response to Board staff interrogatory No. 33, Kenora provided residential bill impacts, holding all other variables constant, associated with a one, two and three year rate riders.

The results of the bill impact scenarios are set out below

Bill IMPACT (-increase over current rates-)				
Residential @ 800 kWh				
% impact	Four year disposition) *	one year disposition	two year disposition	three year disposition
Delivery	32.9%	19.7%	28.7%	31.4%
Total bill	10.0%	6.1%	8.8%	9.6%

Bill IMPACT (-increase in May 2012, all else equal)				
Residential @ 800 kWh				
% impact	Four year dispostion)	one year disposition	two year disposition	three year disposition
Deivery	0.0%	14.7%	6.7%	4.5%
Total Bill	0.0%	4.9%	2.4%	1.6%

* Note: Kenora poropses a four year disposition

Board staff submits that a one year disposition results in significant mitigation by reducing the year-on-year delivery, and total bill impacts for 2011 by 60% and 40% respectively. With a one year recovery, the 2011 bill impact is 19.7% (delivery) and 6.1% (total bill). Under this scenario, in 2012 with the termination of the credit, the delivery and total bill impacts would be 14.75% and 4.9 % respectively. Assuming an IRM increment of about 1.5%, this would have rates in 2012 increase by less that the delivery increase, and slightly more than the total bill increase experienced in 2011.

With respect to deferral account 1562 (Deferred Payments in Lieu of Taxes), Kenora indicated that it is not seeking disposition of the account balance in this application and indicated that it wait until the outcome of the combined PILs (EB-2008-0381) proceeding before initiating a review of the account. Board staff notes that Kenora has not recorded any balances in account 1592. Account 1592 is the account for "PILS and Tax Variances for 2006 and Subsequent Years". Board staff ask that Kenora explain in its reply submission why it has not recorded any amounts it has experienced pursuant to the definition of account 1592.

NEW VARIANCE ACCOUNT

Kenora is requesting Board approval for the establishment of a new variance account to track future charges from the IESO for smart meter entity and MDMR costs. In response to Board staff interrogatory No. 37 Kenora confirmed that its

2010 and 2011 OM&A expenses do not have a provision for these anticipated costs.

In the PowerStream decision, EB-2010-0209, at page 9 the Board concluded, regarding a similar request, that “In terms of tracking the MDM/R costs it is open to the Applicant to do so should these costs arise in advance of PowerStream’s next rate application, but the Board will not establish a formal deferral account at this time.”

Board staff is unaware of any additional certainty subsequent to the PowerStream decision regarding the timing and magnitude of Smart Meter entity charges for both the historical and future periods, and, on this basis submits that the Board should not establish a deferral account at this current time.

LATE PAYMENT PENALTY RECOVERY

In its initial evidence Kenora sought recovery of a one-time expense of $16,378 for the Late Payment Penalty Costs. This is Kenora’s share which it would be required to pay on June 30, 2011 pursuant to the terms of the settlement of the LPP Class Action as approved by the Honourable Mr. Justice Cumming of the Ontario Superior Court on July 22, 2010. Pending further Board action on the matter, Kenora proposed a one year rate rider to recover said amount from ratepayers and the establishment of a variance account to record any difference between the costs paid and the amount collected from customers.

On February 22, 2011 the Board issued its generic decision and order, file EB-2010-0295, regarding the recovery from ratepayers of the costs and damages incurred in the Late Payment Penalty Class Action. On March 4, 2011 Kenora filed its proposed rate riders allowing for the recovery of $16,378 as directed by the Board in its February 22, 2011 Decision and Order. The proposed rate riders are set out in the table below.

Kenora Hydro Electric Corporation Ltd.
Late Payment Settlement Recovery Rate Rider
Board File EB-2010-0295

Class	2009 2.1.5 RRR Distribution Rev	Revenue Proportion	Recovery $ 16,378	2009 2.1.5 Data # Customers	2009 2.1.5 Data # Connections	Annual Charge Per Cust/Conn	Monthly Fixed Rate Rider	Check Monthly RR
Residential	1,189,684.68	59.85%	$ 9,802.25	4,777		$ 2.05	$ 0.17	$ 9,745.08
GS < 50 kW	327,549.58	16.48%	$ 2,698.80	733		$ 3.68	$ 0.31	$ 2,726.76
GS > 50 kW	434,648.78	21.87%	$ 3,581.23	69		$ 51.90	$ 4.33	$ 3,585.24
Streetlights	35,890.38	1.81%	$ 295.71		532	$ 0.56	$ 0.05	$ 319.20
TOTALS	1,987,773.42	100.00%	$ 16,378.00					$ 16,376.28
							Under Collect	$ (1.72)

Board staff has no issues with the calculation, except for the total amount to be recovered. The February 22, 2011 Decision and Order indentified the recoverable amount for Kenora to be $16,296.32. Board staff submits that Kenora should explain in its reply submission why it used $16,378 as the number in its calculation.

Board staff notes that the Board's Decision and Order dated February 22, 2011 does not provide for the establishment of a deferral account and denied the establishment of a variance account to record the difference between the recovery amount and the amount actually recovered from customers. Board staff assumes that Kenora is no longer seeking the establishment of a variance account, and in this regard submits that Kenora its reply submission confirm this understanding.

LOW INCOME ENERGY ASSISTANCE PROGRAM

In response to Board staff interrogatory No. 21, Kenora confirmed that its original application did not include a provision for Low Income Energy Assistance Programs ("LEAP") or for legacy programs such as winter warmth. Kenora calculated that the costs of LEAP, based on 0.12% of the proposed total distribution revenue for 2011 ($3,208,191) would total $3,849.83. Board staffs note that this calculation is consistent with the Board's guidance found in its letter on LEAP Emergency Financial Assistance dated October 20, 2010.

Board staff submits that Kenora should update this calculation in accordance with the approved revenue requirement resulting from the Board's decision on this application, if necessary.

HARMONIZED SALES TAX

In response to Board staff interrogatory No. 6, Kenora stated that the preparation of the 2011 Capital Budget did not include the HST and so no adjustments would be necessary. With respect to the operating budget Kenora noted that the OM&A 2011 budget includes about $13,096 of HST.

In response to Board staff supplemental interrogatory No. 9, Kenora confirmed that its 2011 test year OM&A should be reduced by $13,096.

Board staff has no issues with the adjustment proposed by Kenora.

Kenora also explained that it was unable to record incremental Input Tax Credits ("ITC") in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits) as directed by the Board in its 2010 IRM decision[37], dated April 16, 2010, since the necessary guidance from the Board became available only on December 23, 2010. Kenora Hydro noted that it should have the ITC amount ready by March 28, 2011 and that it would not file this information in this proceeding unless formally requested.

From a practical perspective, Board staff agrees with Kenora. Given the advanced stage of this proceeding, and the relative magnitude of the amount and which would need to be audited, Board staff believes that examination and disposition of this amount should be considered in a subsequent proceeding.

Staff notes that the review and disposition of account 1592 is not typically within the scope of an IRM proceeding. Staff submits that the Board may wish to consider that due to the nature of the costs tracked in this sub-account that this sub-account be brought forward for disposition in the next rate proceeding for Kenora, which would be Kenora's 2012 IRM application. Delaying disposition of this sub-account until Kenora's next rebasing application (2015) would represent an unreasonably long delay in providing customers with the benefit of the ITCs. Staff also notes that this is a generic issue that would apply to all applicants that have a deferral account for ITCs and that are scheduled to file an IRM application

[37] Excerpt from the Board's Decision and Order EB-2009-0200 p.6 "The Board therefore directs that, beginning July 1, 2010, Kenora Hydro shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs)) the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of Kenora Hydro's next cost of service rate order. 50 % of the confirmed balances in the account shall be returnable to the ratepayers."

for 2012 rates.

IMPLEMENTATION

Kenora filed its application on November 1, 2011 for rates effective May 1, 2011. This is about 2 months later than expected, for new rates to have been approved and ordered by the Board in time for a May 1, 2011 implementation. In response to Kenora's request, the Board declared Kenora's current rates interim, effective May 1, 2011 in Procedural Order No. 2 and Order for Interim Rates issued on February 24, 2011.

In response to Board staff supplemental interrogatory No.1 Kenora indicated that it "…does not have the expectation that potential under-recovered revenues between the period May 1, 2011 and the time new rates are implemented will be recouped."

In addition, Board staff notes that the Applicant delayed in filing responses to the first round of interrogatories by 10 days. However, Board staff submits that the Applicant has made a significant effort to respond to all interrogatories and to update its application accordingly. Board staff is of the view that a further delay in the effective date beyond the two months noted above for the filing of the initial application is not warranted. Given the current timing and circumstances, Board staff submits that the Board may wish to approve a July 1, 2011 effective date and that the rates can be implemented on this same date barring any further delays in this proceeding.

All of which is respectfully submitted

ATTACHMENT A

Corrections and adjustments proposed by Kenora during interrogatory process

VECC IR # 47		
Kenora Hydro		
Corrections to Rate Application		
	2011 OM&A Expenses (Reduced) Increased	**2011 Capital Spending (Reduced) Increased**
OEB IR's - Round 1		
OEB IR # 6		
OM&A savings due to PST cost reductions	(13,096)	
	Amortization	
OEB IR # 13	1/2 Yr rule	
Reduce Overhead Conductors Budget	(400)	(20,000)
Line Transformers - Capital Contribution missed	(680)	(34,000)
Main copier - purchase delayed	(750)	(15,000)
Tools, Shop & Equipment reduced budget	(125)	(2,500)
Miscellaneous Equipment reduced budget	(100)	(2,000)
OEB IR # 21		
Increase costs due to LEAP program	3,850	
OEB IR # 22		
Increase costs due to OMERS increase	1,167	
OEB IR # 24		
Error - Reduce City allocated costs	(40,434)	
OEB IR's - Round 2		
None noted		
VECC IR's - Round 1		
VECC IR # 21		
Reduced budgeted interest on LTDebt	(74,776)	
VECC IR's - Round 2		
VECC IR # 42		
Reduced estimated Rate Application costs	(21,053)	
(Total reduction = $84,212, Amortized over 4 yrs)		
VECC IR # 45		
Error - Remove smart meter amortization on additions	(500)	
Total Impact	**(146,897)**	**0**
	2011 OM&A Expenses (Reduced) Increased	**2011 Capital Spending (Reduced) Increased**