Exhibit 7:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 2): Cost Allocation Model

OVERVIEW OF COST ALLOCATION

Overview of Cost Allocation

On September 29, 2006 the Ontario Energy Board (the "Board") issued Board Directions on Cost Allocation Methodology for Electricity Distributors ("the Directions"). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model ("the Model") and User Instruction (the Instructions") for the Model. WPI prepared its information filing consistent with WPI's understanding of the Directions, the Guidelines, the Model and the Instructions and submitted it to the Board on March 31, 2006.

One of the main objectives of this cost allocation filing was to provide evidence to show WPI's rate classifications that are being subsidized by other classes and those rate classifications that are over contributing based on the assumptions of the Model.

In its 2009 Cost of Service Application (EB-2008-0250); the applicant did not submit a new cost allocation study; however, did adjust the cost allocation model for the treatment of the Transformer Allowance.

On March 31, 2011 the Board issued its *Report of the Board on the Review of Electricity Distribution Cost Allocation Policy*, EB-2010-0219. This report contained several revisions to the Board's policy with respect to cost allocation that were to be implemented through cost of service applications beginning with the 2012 test year. On June 28, 2012, the Board issued a revised Cost Allocation model. WPI has adhered to direction and policy set up in the Board's report and has used the Cost Allocation Model provided by Board in preparing this Application.

2009 Cost of Service Cost Allocation Results

Please see attached Sheet O1 from the Cost Allocation Information Filings which were previously submitted as part of WPI's 2009 COS filing EB-2008-0250.

2006 COST ALLOCATION INFORMATION FILING
Westario Power Inc.
EB-2005-0434 EB-2007-0003
Friday, April 13, 2007

Ontario

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$7,776,630	$4,852,504	$1,099,132	$1,606,590	$190,244	$523	$27,637
mi	Miscellaneous Revenue (mi)	$563,220	$394,105	$98,609	$51,293	$13,798	$26	$5,389
	Total Revenue	$8,339,850	$5,246,609	$1,197,741	$1,657,883	$204,042	$549	$33,026
	Expenses							
di	Distribution Costs (di)	$1,066,417	$678,522	$163,181	$143,047	$80,099	$100	$1,468
cu	Customer Related Costs (cu)	$1,388,039	$930,481	$319,223	$125,039	$480	$22	$12,794
ad	General and Administration (ad)	$2,058,126	$1,348,688	$396,129	$227,613	$74,470	$109	$11,117
dep	Depreciation and Amortization (dep)	$1,271,615	$830,399	$193,073	$160,490	$85,822	$108	$1,723
INPUT	PILs (INPUT)	$723,062	$471,115	$109,844	$92,523	$48,580	$61	$938
INT	Interest	$637,092	$415,102	$96,784	$81,523	$42,804	$54	$826
	Total Expenses	$7,144,351	$4,674,307	$1,278,236	$830,234	$332,254	$454	$28,866
	Direct Allocation	$181,017	$131,578	$34,055	$12,723	$81	$4	$2,575
NI	Allocated Net Income (NI)	$1,122,850	$731,600	$170,578	$143,680	$75,441	$94	$1,456
	Revenue Requirement (includes NI)	$8,448,218	$5,537,485	$1,482,870	$986,638	$407,776	$552	$32,897
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$25,043,439	$16,361,102	$3,807,634	$3,075,384	$1,763,809	$2,205	$33,304
gp	General Plant - Gross	$368,800	$240,993	$56,020	$45,188	$26,072	$33	$494
accum dep	Accumulated Depreciation	($3,969,726)	($2,590,428)	($606,561)	($493,305)	($273,995)	($341)	($5,095)
co	Capital Contribution	($1,774,197)	($1,196,452)	($269,172)	($111,064)	($194,073)	($241)	($3,195)
	Total Net Plant	$19,668,316	$12,815,216	$2,987,922	$2,516,203	$1,321,813	$1,655	$25,507
	Directly Allocated Net Fixed Assets	$145,054	$105,437	$27,289	$10,195	$65	$4	$2,064
COP	Cost of Power (COP)	$30,363,546	$14,244,900	$4,934,989	$10,807,482	$337,584	$926	$37,666
	OM&A Expenses	$4,512,582	$2,957,690	$878,534	$495,699	$155,049	$231	$25,379
	Directly Allocated Expenses	$166,551	$121,063	$31,334	$11,706	$74	$4	$2,370
	Subtotal	*$35,042,679*	*$17,323,653*	*$5,844,857*	*$11,314,887*	*$492,707*	*$1,161*	*$65,415*
	Working Capital	$5,256,402	$2,598,548	$876,728	$1,697,233	$73,906	$174	$9,812
	Total Rate Base	$25,069,772	$15,519,201	$3,891,939	$4,223,631	$1,395,784	$1,833	$37,384
		Rate Base Input equals Output						
	Equity Component of Rate Base	$12,534,886	$7,759,600	$1,945,970	$2,111,815	$697,892	$916	$18,692
	Net Income on Allocated Assets	$1,014,482	$440,725	($114,550)	$814,926	($128,293)	$91	$1,584
	Net Income on Direct Allocation Assets	$6,542	$4,755	$1,231	$460	$3	$0	$93
	Net Income	$1,021,024	$445,480	($113,320)	$815,385	($128,290)	$91	$1,677
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	98.72%	94.75%	80.77%	168.03%	50.04%	99.35%	100.39%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($108,368)	($290,876)	($285,129)	$671,245	($203,734)	($4)	$129
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.15%	5.74%	-5.82%	38.61%	-18.38%	9.94%	8.97%

2013 Cost Allocation Study

To perform the 2013 cost allocation study, WPI retained the services of Elenchus Research Associates Inc. ("Elenchus"). All distribution system attributes, financial, load and customer information was provided to Elenchus by WPI. WPI also developed and provided the various weighting allocators such as weighting for services, metering and billing and collecting that are contained in the Cost Allocation Study.

2013 Cost Allocation Study Results

The results of the 2013 Cost Allocation Study as well as the report completed by Elenchus are presented in Exhibit 7, Tab 1, Schedule 1, Attachment 1. A hard copy of Sheets I-6 and I-8, and output sheets O-1 and O-2 of the completed OEB Cost Allocation Model can be found at Exhibit 7, Tab 1, Schedule 1, Attachment 3.

Westario Power Inc.
2013 Cost Allocation Study

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Westario Power Inc.

September 24, 2012

elenchus

Table of Contents

1 INTRODUCTION

Westario Power Inc. ("Westario") has prepared its 2013 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the June 28, 2012 update to the document entitled *Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications* ("Filing Requirements").

Section 2.10 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

> *A completed cost allocation study using the Board approved methodology must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. The 2011 update of the model issued by the Board will be available on the Board's web site.*

Westario asked Elenchus Research Associated (Elenchus)[1] to assist it by preparing an appropriate cost allocation study for its 2013 cost of service rate application. In addressing this issue, Elenchus was guided by the Filing Requirements and the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors".[2]

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report.*

The "influencing factors" discussed in section 2.3 of the report are:

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5)

---

[1] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Westario and documented in this report. John Todd's curriculum vitae is available at www.elenchus.ca.

[2] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

- **Limited modelling experience:** The Board observed that “the cost allocation model is complex, and the data required for the model was not always readily available for modelling.” (p. 6)
- **Status of current rate classes:** The Board points out that “Any changes in customer classification or load data could have a significant impact on future cost allocation studies” (p. 6).
- **Managing the movement of rates closer to allocated costs:** The Board notes:

> *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (p. 6)*

In utilizing the Board’s cost allocation model for Westario’s 2013 cost allocation study, Elenchus has been cognizant of these “influencing factors” as they apply to Westario.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2013 forward test year, the primary purpose of the cost allocation study (“CA Study”) is to determine the proportions of a distributor’s total revenue requirement that are the “responsibility” of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, the desired results can be achieved in either of two ways.

- **Prospective Year CA Study:** A cost allocation study for the 2013 test year can be based on an allocation of the 2013 test year costs (i.e., the 2013 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Assuming there is a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

- **Historic Year CA Study:** As an alternative, an historic year cost allocation study can be prepared that determines the proportion of costs allocated to each class for the most recent historic year. In the case, the CA Study will rely on actual costs, weather adjusted loads, customer counts, etc. that are not affected by forecast errors. Assuming the costs and loads are relatively stable so that the proportionate cost responsibility of each rate class in the historic year is a reasonable proxy for the 2013 test year cost responsibility, the resulting proportionate cost responsibilities can be used to allocate the 2013 revenue requirement to the various classes.

The Westario CA Study uses the first of these methods in order to ensure compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". Relying on a Prospective Year CA Study is also appropriate at this time since the Ontario economy has suffered over the past three years and, as a result, many distributors have experienced significant changes in the load profiles of their customer classes. These changes could have a significant impact on the allocation of costs to the classes and the resulting revenue to cost ratios. This approach implicitly assumes that the economic recovery will be slow and, as a result, the relative loads of customer classes are more likely to reflect 2013 loads than 2011 loads during the next IRM cycle.

1.2 WESTARIO'S 2009 COST ALLOCATION INFORMATION FILING

Westario has not filed a prior cost allocation, and asked Elenchus to prepare its 2013 cost allocation from scratch. This model was performed in accordance with the internal documentation in the v 3 Cost Allocation Model (CA Model).

Westario's 2009 CAIF relied on the Board's 2006 Cost Allocation Model ("CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity*

Distributors ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* (“the Instructions").

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Westario CA Study, explaining the model run included in the study, as well as the load and cost information used for the run. Section 3 explains the methodology used to develop the 2013 Westario model by documenting each step taken in completing the model. Section 4 summarizes the results of the Westario CA Study, showing the class revenue requirements and revenue to cost ratios generated by the CA model.

2 OVERVIEW OF THE WESTARIO 2013 CA STUDY

2.1 MODEL RUN INCLUDED IN THE WESTARIO COST ALLOCATION STUDY

Section 2.10.3 of the updated Filing Requirements specifies that the third table in Appendix 2-P, "...includes the following information for each class" that should be provided based on:

- "The previously approved ratios most recently implemented by the distributor;
- "The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and
- "The ratios that are proposed for the Test Year, which are the proposed class revenues, together with the updated cost allocation model" which is the appropriate 2013 model.

For clarity, the following designations are used.

- **Westario-2009**: The Westario 2009 revenue to cost ratios.
- **Westario-2013:** The version 3 CA Model with 2013 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "This filing must reflect future loads and costs..." and "If updated load profiles are not available, the load profiles of the classes may be the same as those provided by Hydro One for use in the Informational Filing, scaled to match the load forecast as it relates to the respective rate classes", (Section 2.10.1, p. 42)

The Westario 2013 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2013 load forecast and customer counts by class being used by Westario in its application were also used for the 2013 CA models. Westario's load forecast was prepared by Elenchus.
- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF were used for all classes.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2013 models for the following reasons.

1. Elenchus explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as Elenchus is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. There would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information will be available in the next few years at minimal incremental cost.
4. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter the hourly load profiles of the affected classes.

5. The 2006 hourly load profiles were based on 2004 actual loads and updated hourly load profiles would be based on 2011 actual loads.
6. There are no Intermediate or Large User customers in the Westario service area.

2.3 COST INFORMATION

As noted earlier, Elenchus' preferred methodology for preparing 2013 cost allocation models is to use the prospective 2013 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2013 test year. In the case of Westario, the financial information for the forecast year has been prepared at the USoA level consistent with the level of detail embedded in the OEB's cost allocation model. [3]

[3] Some information (i.e., meter counts and some amortization detail) that is used in the Board's CA Model is not explicitly forecasted for the test year. These values were estimated using scaling factors based on prior year ratios. For example, the ratio of meters to customers was assumed to be constant. The portion of the total costs accounted for in this manner was too small for any plausible estimation errors to have a significant impact on the test year revenue to cost ratios.

3 WESTARIO COST ALLOCATION STUDY METHODOLOGY

This section documents Elenchus' methodology for the Westario Cost Allocation Study, the 2013 CA Model.

3.1 2013 WESTARIO CA MODEL

3.1.1 HOURLY LOAD PROFILE (HONI FILE)

For the Westario CAIF, HONI provided data files with three worksheets that were to be used as input to the 2009 CAIF:

- **Data Summary:** actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- **Hourly Load Shape by Class:** GWh by class for each hour in 2004.
- **Input to Cost Allocation Model**: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Westario hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2013. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2013 load forecast while maintaining the hourly load shapes.

3.1.2 DEMAND ALLOCATORS (HONI FILE)

The demand allocators used in the Westario-2013 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2013 hourly load profiles resulting from the preceding step. Using the 2013 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.1.3 2013 Demand Data (Westario-2013 Model)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2013 Westario CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) for GS > 50 are not equal to the full class NCP values since not all GS>50 customers use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

3.1.4 2013 Customer Data (Westario-2013 Model)

The 30 year weather normalized kWh by rate class which was an input from the Hydro One file at Sheet I6 Customer Data row 27 in the 2006 CA model was replaced with the 2013 load forecast in the 2013 CA Model at Sheet I6.1 Revenue row 50.

In addition, the demand data (kW and kWh) in rows 25, 26, and 27 of Sheet I6.1 Revenue were replaced with the forecasted values. Row 27 was scaled by the percentage change in row 26.

The 2013 Distribution Revenue in row 39 was derived using the forecast demand (kW and kWh) and customer counts by rate class and the existing 2012 rates.

3.1.5 2013 Revenue to Cost Ratios

Since Westario is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2013. The 2013 total revenue to cost ratio at current rates is less than 100% by the amount of the required rate increase. The revenue to cost ratios of the classes reflect the costs allocated to the classes based on the OEB CA Model methodology and the revenues that would be generated at current rates given the forecast demand (kW and kWh) and customer counts by rate class for 2013.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Westario cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	Westario-2009	Westario-2013 Status Quo Rates	Board Target Range
Residential	95.55	92.41	85-115
GS < 50 kW	81.38	99.23	80-120
GS > 50 kW	162.33	152.01	80-120
Street Lighting	74.88	71.87	70-120
Sentinel Light	71.03	52.00	80-120
USL	100.00	232.47	80-120
Total	100.00	100.00	

The Westario-2013 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2013 forecast test year.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	Westario-2009		Westario-2013	
	$	%	$	%
Residential	5,496,182	65.62	7,196,715	68.02
GS < 50 kW	1,476,358	17.63	1,461,393	13.81
GS > 50 kW	970,136	11.58	1,351,071	12.77
Street Lighting	399,848	4.77	559,656	5.29
Sentinel Light	543	0.01	1,239	0.01
USL	33,054	0.39	9,627	0.09
Total	8,376,121	100.00	10,579,701	100.00

5 FIXED CHARGE RATES

The Westario cost allocation model produced the following customer unit cost per month values:

Table 9: 2013 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC[4] Adjustment
Residential	5.89	8.77	17.01
GS < 50 kW	4.45	7.37	18.88
GS > 50 kW	31.88	50.96	86.77
Street Lighting	-0.08	-0.06	7.63
Sentinel Light	1.47	2.45	8.19
USL	1.44	2.43	9.95

In accordance with Board policy,[5] the following boundary values would apply for the fixed monthly service charge:

[4] PLCC: ‘Peak Load Carrying Capacity’
[5] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, pages 12-13

Table 10: 2013 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	5.89	17.01	11.34	5.89	17.01
GS < 50 kW	4.45	18.88	20.77	4.45	20.77
GS > 50 kW	31.88	86.77	240.15	31.88	240.15
Street Lighting	-0.08	7.63	3.88	-0.08	7.63
Sentinel Light	1.47	8.19	2.53	1.47	8.19
USL	1.44	9.95	11.30	1.44	11.30

File Number:	EB2012-0176
Exhibit:	7
Tab:	1
Schedule:	1
Attachment:	2
Date:	09-Oct-12

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	**%**
Residential	$ 5,496,182	65.62%	$ 7,196,715	68.02%
GS < 50 kW	$ 1,476,358	17.63%	$ 1,461,393	13.81%
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 970,136	11.58%	$ 1,351,071	12.77%
GS > xxx kW, if applicable		0.00%		0.00%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 399,848	4.77%	$ 559,656	5.29%
Sentinel Lighting	$ 543	0.01%	$ 1,239	0.01%
Unmetered Scattered Load (USL)	$ 33,054	0.39%	$ 9,627	0.09%
Other class, if applicable		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%		0.00%
Total	$ 8,376,121	100.00%	$ 10,579,701	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	**Column 7B** Load Forecast (LF) X current	**Column 7C** L.F. X current approved rates X	**Column 7D** LF X proposed rates	**Column 7E** Miscellaneous Revenue
Residential	$ 5,605,008	$ 6,223,997	$ 6,645,846	$ 426,526
GS < 50 kW	$ 1,205,485	$ 1,338,613	$ 1,359,406	$ 111,502
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 1,779,790	$ 1,976,340	$ 1,543,837	$ 77,448
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$ 329,107	$ 365,452	$ 365,795	$ 36,797
Sentinel Lighting	$ 496	$ 550	$ 897	$ 94
Unmetered Scattered Load (USL)	$ 19,549	$ 21,708	$ 10,879	$ 673
Other class, if applicable				
Embedded distributor class				
Total	$ 8,939,435	$ 9,926,660	$ 9,926,660	$ 653,040

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2009	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	95.55	92.41	98.27	85 - 115
GS < 50 kW	81.38	99.23	100.65	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	162.33	152.01	120.00	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	74.88	71.87	71.94	70 - 120
Sentinel Lighting	71.03	51.98	79.98	80 - 120
Unmetered Scattered Load (USL)	100.00	232.48	120.00	80 - 120
Other class, if applicable				
Embedded distributor class				

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants that have had rates adjusted only under IRM 2, the Most Recent Year is 2006, and the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2013	2014	2015	
	%	%	%	%
Residential	98.27			85 - 115
GS < 50 kW	100.65			80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	120.00			80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	71.94			70 - 120
Sentinel Lighting	79.98			80 - 120
Unmetered Scattered Load (USL)	120.00			80 - 120
Other class, if applicable				0
				0
Embedded distributor class				

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2012 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2013 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2013 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be

Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

2013 Cost Allocation Model

Sheet I6.1 Revenue Worksheet - Initial Submission

Total kWhs from Load Forecast	441,225,879
Total kWs from Load Forecast	491,322
Deficiency from RRWF	- 987,226
Miscellaneous Revenue	653,041

Billing Data

			1	2	3	7	8	9
	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Forecast kWh	CEN	441,225,879	202,711,942	64,088,366	168,781,699	5,355,530	17,900	270,442
Forecast kW	CDEM	491,322			476,416	14,889	17	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		155,000			155,000			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	441,225,879	202,711,942	64,088,366	168,781,699	5,355,530	17,900	270,442
kWh - 30 year weather normalized amount		441,225,879	202,711,942	64,088,366	168,781,699	5,355,530	17,900	270,442
Existing Monthly Charge			$11.34	$20.77	$240.15	$3.88	$2.53	$11.30

Existing Distribution kWh Rate			$0.0142	$0.0092				$0.0422
Existing Distribution kW Rate					$2.2373	$3.2599	$13.0802	
Existing TFOA Rate			$0.60	$0.60	$0.60	$0.60	$0.60	$0.60
Additional Charges								
Distribution Revenue from Rates		$9,032,434	$5,605,008	$1,205,485	$1,872,790	$329,107	$496	$19,549
Transformer Ownership Allowance		$93,000	$0	$0	$93,000	$0	$0	$0
Net Class Revenue	CREV	$8,939,434	$5,605,008	$1,205,485	$1,779,790	$329,107	$496	$19,549
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		8,939,434	5,605,008	1,205,485	1,779,790	329,107	496	19,549

Weather Normalized Data from Hydro One

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	472,111,691	216,901,778	68,574,552	180,596,418	5,730,417	19,153	289,373
Loss Factor		**1.0700**	**1.0700**	**1.0700**	**1.0700**	**1.0700**	**1.0700**

2013 Cost Allocation Model

Sheet I8 Demand Data Worksheet - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	84,544	44,347	12,673	27,493	-	-	31
Bulk Delivery CP	BCP1	84,544	44,347	12,673	27,493	-	-	31
Total Sytem CP	DCP1	84,544	44,347	12,673	27,493	-	-	31
4 CP								
Transformation CP	TCP4	320,620	174,708	42,815	101,673	1,297	4	123
Bulk Delivery CP	BCP4	320,620	174,708	42,815	101,673	1,297	4	123
Total Sytem CP	DCP4	320,620	174,708	42,815	101,673	1,297	4	123
12 CP								
Transformation CP	TCP12	821,450	406,061	116,067	296,404	2,541	8	369
Bulk Delivery CP	BCP12	821,450	406,061	116,067	296,404	2,541	8	369
Total Sytem CP	DCP12	821,450	406,061	116,067	296,404	2,541	8	369
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	95,643	50,999	14,255	28,931	1,413	5	40
Primary NCP	PNCP1	95,643	50,999	14,255	28,931	1,413	5	40
Line Transformer NCP	LTNCP1	95,643	50,999	14,255	28,931	1,413	5	40
Secondary NCP	SNCP1	66,712	50,999	14,255		1,413	5	40
4 NCP								
Classification NCP from Load Data Provider	DNCP4	360,853	189,686	52,953	112,946	5,106	17	145
Primary NCP	PNCP4	360,853	189,686	52,953	112,946	5,106	17	145
Line Transformer NCP	LTNCP4	360,853	189,686	52,953	112,946	5,106	17	145
Secondary NCP	SNCP4	247,907	189,686	52,953		5,106	17	145
12 NCP								
Classification NCP from Load Data Provider	DNCP12	932,250	449,941	146,417	320,779	14,674	50	389
Primary NCP	PNCP12	932,250	449,941	146,417	320,779	14,674	50	389
Line Transformer NCP	LTNCP12	932,250	449,941	146,417	320,779	14,674	50	389
Secondary NCP	SNCP12	611,471	449,941	146,417		14,674	50	389

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet - Initial Submission

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue at Existing Rates	$8,939,434	$5,605,008	$1,205,485	$1,779,790	$329,107	$496	$19,549
mi	Miscellaneous Revenue (mi)	$653,040	$426,526	$111,502	$77,448	$36,797	$94	$673
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$9,592,474	$6,031,534	$1,316,987	$1,857,237	$365,904	$589	$20,222
	Factor required to recover deficiency (1 + D)	1.1104						
	Distribution Revenue at Status Quo Rates	$9,926,661	$6,223,997	$1,338,613	$1,976,341	$365,452	$550	$21,708
	Miscellaneous Revenue (mi)	$653,040	$426,526	$111,502	$77,448	$36,797	$94	$673
	Total Revenue at Status Quo Rates	$10,579,701	$6,650,523	$1,450,115	$2,053,788	$402,249	$644	$22,380
	Expenses							
di	Distribution Costs (di)	$2,484,000	$1,618,528	$363,132	$309,188	$190,032	$336	$2,785
cu	Customer Related Costs (cu)	$1,445,000	$1,153,225	$172,802	$116,381	$1,214	$180	$1,199
ad	General and Administration (ad)	$2,396,500	$1,682,481	$327,785	$264,470	$119,041	$312	$2,411
dep	Depreciation and Amortization (dep)	$1,379,137	$901,289	$186,724	$224,164	$65,958	$111	$890
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0	$0
INT	Interest	$1,386,586	$887,970	$198,193	$210,693	$88,455	$145	$1,130
	Total Expenses	$9,091,223	$6,243,493	$1,248,636	$1,124,896	$464,700	$1,083	$8,414
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,488,478	$953,222	$212,757	$226,176	$94,955	$155	$1,213
	Revenue Requirement (includes NI)	$10,579,701	$7,196,715	$1,461,393	$1,351,071	$559,656	$1,239	$9,627
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$57,259,940	$36,885,784	$8,214,460	$8,219,684	$3,882,673	$6,459	$50,880
gp	General Plant - Gross	$5,618,874	$3,629,726	$804,055	$800,738	$378,715	$632	$5,008
accum dep	Accumulated Depreciation	($21,120,626)	($13,540,215)	($3,042,961)	($3,069,521)	($1,446,863)	($2,396)	($18,671)
co	Capital Contribution	($6,807,472)	($4,581,161)	($979,502)	($659,850)	($577,350)	($1,029)	($8,580)
	Total Net Plant	$34,950,716	$22,394,135	$4,996,053	$5,291,051	$2,237,175	$3,665	$28,637
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$45,548,250	$20,926,185	$6,615,915	$17,423,527	$552,857	$1,848	$27,918
	OM&A Expenses	$6,325,500	$4,454,233	$863,719	$690,039	$310,287	$828	$6,394
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$51,873,750*	*$25,380,418*	*$7,479,634*	*$18,113,566*	*$863,145*	*$2,676*	*$34,312*
	Working Capital	$6,743,588	$3,299,454	$972,352	$2,354,764	$112,209	$348	$4,461
	Total Rate Base	$41,694,303	$25,693,589	$5,968,405	$7,645,815	$2,349,384	$4,013	$33,097
		Rate Base Input equals Output						
	Equity Component of Rate Base	$16,677,721	$10,277,436	$2,387,362	$3,058,326	$939,754	$1,605	$13,239
	Net Income on Allocated Assets	$1,488,478	$407,031	$201,479	$928,893	($62,451)	($439)	$13,966
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$1,488,478	$407,031	$201,479	$928,893	($62,451)	($439)	$13,966
	RATIOS ANALYSIS							

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet - Initial Submission

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
REVENUE TO EXPENSES STATUS QUO%	100.00%	92.41%	99.23%	152.01%	71.87%	52.00%	232.47%
EXISTING REVENUE MINUS ALLOCATED COSTS	($987,226)	($1,165,180)	($144,406)	$506,166	($193,752)	($649)	$10,595
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($546,191)	($11,278)	$702,717	($157,407)	($595)	$12,753
RETURN ON EQUITY COMPONENT OF RATE BASE	8.92%	3.96%	8.44%	30.37%	-6.65%	-27.37%	105.49%

2013 Cost Allocation Model

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Initial Submission

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$5.89	$4.45	$31.88	-$0.08	$1.47	$1.44
Customer Unit Cost per month - Directly Related	$8.77	$7.37	$50.96	-$0.06	$2.45	$2.43
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$17.01	$18.88	$86.77	$7.63	$8.19	$9.95
Existing Approved Fixed Charge	$11.34	$20.77	$240.15	$3.88	$2.53	$11.30

Exhibit 7: Cost Allocation

Tab 2 (of 2): Revenue Allocation and Revenue-to-Cost Ratios

REVENUE ALLOCATION AND REVENUE-TO-COST RATIOS

The following table shows the current Revenue to Cost ratios based on the 2009 Cost of Service Application along with WPI's proposed target ratios and the Board-prescribed ranges for these ratios:

	2009	Targets	Prescribed Range	Proposed Ratios
Residential	92%	85-115	85%-115%	98%
GS<50	99%	80-120	80%-120%	101%
GS>50	152%	80-120	80%-120%	120%
USL	232%	70-120	70%-120%	120%
Sentinel Lights	72%	70-120	70%-120%	72%
Street Lights	52%	80-120	80%-120%	80%

Revenue to Cost ratios for General Service greater than 50 kW, Unmetered Scattered Load (USL) and Sentinel Lights all fell outside of the applicable prescribed range. WPI therefore proposes to move these ratios to the applicable floor or ceiling boundary.

For both Residential and General Service less than 50 kW, the Revenue to Cost ratio was within the prescribed range. In order to move the General Service greater than 50 kW, Unmetered Scattered Load (USL) and Sentinel Lights the WPI with the prescribed ranges, WPI proposes to move both Residential and General Service less than 50 kW closer to the 100% mark.

In previous decisions on cost of service applications for electricity distributors, the Board has ordered that where the Revenue to Cost ratio for a rate class was well below the applicable prescribed range, the ratio should move halfway to the floor boundary in the Test year, with the outstanding gap to be closed over the following one or two years of the Incentive Regulation period. Although this approach could be applied to the USL class, considering the relatively high bill impacts of the USL class, WPI's view is that, since the USL class represents less than 1% of the total revenue requirement, it does not warrant a rate mitigation plan or a readjustment of its Revenue to Cost ratios over a period of multiple years.

Attachment 1 to this schedule shows the results of the proposed Revenue to Cost ratios on the allocation of Test Year revenue

Westario Power (ED-2002-0515)

2013 EDR Application () version: 1
October 9, 2012

Exhibit 7
Tab 2
Schedule 1
Attachment 1

F3 Revenue Requirement Allocation

Enter allocation of Base Revenue Requirement and RC ratio ranges by customer class

Customer Class Name	Base Revenue Requirement %			Base Revenue Requirement $ [3]		
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application
Residential	68.20%	62.70%	66.95%	6,770,188	6,223,997	6,645,846
General Service < 50 kW	13.60%	13.49%	13.69%	1,349,891	1,338,613	1,359,406
General Service > 50 to 4999 kW	12.83%	19.91%	15.55%	1,273,623	1,976,340	1,543,837
Unmetered Scattered Load	0.09%	0.22%	0.11%	8,954	21,708	10,879
Street Lighting	5.27%	3.68%	3.68%	522,859	365,452	365,795
Sentinel Lighting	0.01%	0.01%	0.01%	1,145	550	897
TOTAL	**100.00%**	**100.00%**	**100.00%**	**9,926,660**	**9,926,660**	**9,926,660**
			OK			**OK**

[1] from sheet F2
[2] from sheet C3
[3] Base Revenue Requirement (from sheet F1) multiplied by Base Revenue Requirement %

Customer Class Name	Revenue Offsets [4]		Base Revenue Requirement $			Service Revenue Requirement $ [5]		
	%	$	Cost Allocation	Existing Rates	Rate Application	Cost Allocation	Existing Rates	Rate Application
Residential	65.31%	426,526	6,770,188	6,223,997	6,645,846	7,196,715	6,650,523	7,072,372
General Service < 50 kW	17.07%	111,502	1,349,891	1,338,613	1,359,406	1,461,393	1,450,115	1,470,908
General Service > 50 to 4999 kW	11.86%	77,448	1,273,623	1,976,340	1,543,837	1,351,071	2,053,788	1,621,285
Unmetered Scattered Load	0.10%	673	8,954	21,708	10,879	9,627	22,381	11,552
Street Lighting	5.63%	36,797	522,859	365,452	365,795	559,656	402,249	402,592
Sentinel Lighting	0.01%	94	1,145	550	897	1,239	644	991
TOTAL	**100.00%**	**653,041**	**9,926,660**	**9,926,660**	**9,926,660**	**10,579,701**	**10,579,701**	**10,579,701**

[4] %s from sheet F2: total $ from sheet F1
[5] Revenue Offsets plus Base Revenue Requirement

Customer Class Name	Service Revenue Requirement			Cost Allocation	Variance	Target Range	
	Rate Application	Cost Allocation	Revenue to Cost Ratio [6]	Revenue to Cost Ratio [7]		Floor	Celiling
Residential	7,072,372	7,196,715	0.98	0.92	0.06	0.85	1.15
General Service < 50 kW	1,470,908	1,461,393	1.01	0.99	0.01	0.80	1.20
General Service > 50 to 4999 kW	1,621,285	1,351,071	1.20	1.52	(0.32)	0.80	1.20
Unmetered Scattered Load	11,552	9,627	1.20	2.32	(1.12)	0.70	1.20
Street Lighting	402,592	559,656	0.72	0.72	0.00	0.70	1.20
Sentinel Lighting	991	1,239	0.80	0.52	0.28	0.80	1.20
TOTAL	**10,579,701**	**10,579,701**	**1.00**	**1.00**			

[6] Rate Application value divided by Cost Allocation value
[7] from sheet F2

Exhibit 8:

RATE DESIGN

Exhibit 8: Rate Design

Tab 1 (of 4): Existing Rates

OVERVIEW OF EXISTING RATES

Exhibit 8, Tab 1, Schedule 1, Attachment 1 presents the schedule of existing approved rates which came into effect May 1, 2012.

The existing rates for Specific Service Charges, Retail Services Charges and Loss Factors were approved by the Board in 2009 as part of the utility's cost of service application.

The class-specific rates for the monthly service charge and distribution volumetric result from the cost of service approval in 2009 and annual adjustments in 2010, 2011 and 2012 under the Board's 3rd Generation Incentive Regulation Mechanism ("3GIRM").

The Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP-IPI) as published by Statistics Canada is typically used as the price escalator for IRM applications. The GDP-IPI is the annual percentage change in the current calendar year. (i.e. For rates effective May 1, 2013, the GDP-IPI will be the annual percentage change for calendar year 2012.)

Table 1 below summarizes the fixed charge rates and volumetric rates since WPI's last Cost of Service application in 2009.

Table 1: Historical Fixed and Variable Charges

		2009 Cos	2010	2011	2012
Res	Fixed Charge	$12.23*	$11.22	$11.24	$11.34
	Volumetric	$0.0153	$0.0141	$0.0141	$0.142
GS<50	Fixed Charge	$21.57*	$20.55	$20.59	$20.77
	Volumetric	1.0102	$0.0091	0.0091	$0.0092
GS>50	Fixed Charge	$238.89*	$237.63	$238.06	$240.15
	Volumetric	$2.6152	$2.2138	$2.2178	$2.2373
USL	Fixed Charge	$11.19	$11.18	$11.20	$11.30
	Volumetric	$0.0428	$0.0417	$0.0418	$0.0422
Sentinel Light	Fixed Charge	$2.51	$2.51	$2.51	$2.53
	Volumetric	$13.2721	$12.9428	$12.9661	$13.0802
Street Lights	Fixed Charge	$3.84	$3.84	$3.85	$3.88
	Volumetric	$3.5371	$3.2257	$3.2315	$3.2599

'* fixed charges include smart meter adder of $1.00

Table 2 below shows the current approved rate riders while the following table, Table 3, summarizes these revenue projections, showing the proportions attributable to fixed (monthly service) charges and variable (distribution volumetric) charges.

Table 2: 2012 Approved Rate Riders

	Billing	Residential	General Service < 50 kW	General Service > 50 to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Rate Rider for Global Adjustment Sub-Account	Volumetric	-0.0003	-0.0003	-0.1048	-0.0003	0	-0.1653
Rate Rider for Deferral/Variance Account Disposition	Volumetric	-0.0015	-0.0015	-0.577	-0.0012	-0.0012	-1.1627
LV Charges	Volumetric	0.0012	0.0011	0.399	0.0011	0.3153	0.3079
LRAM	Volumetric	0.0007	0.0002	0.0244			
Tax Adjustment	Volumetric	-0.0003	-0.0002	-0.0371	-0.0006	-0.2288	-0.278

Table 3: Revenues from Existing Fixed and Variable Charges

Customer Class Name	**2012 PROJECTED REVENUE FROM EXISTING VARIABLE CHARGES**							
Residential	**Variable Distribution Rate**	**per**	**Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
General Service < 50 kW	$0.0142	kWh	204,668,826	2,906,297	$0.00		0	2,906,297
General Service > 50 to 4999 kW	$0.0092	kWh	65,051,695	598,476	$0.00		0	598,476
Unmetered Scattered Load	$2.2373	kW	475,388	1,063,586	($0.60)	155,000	-93,000	970,586
Street Lighting	$0.0422	kWh	278,866	11,768	$0.00		0	11,768
Sentinel Lighting	$3.2599	kW	15,101	49,228	($0.60)		0	49,228
TOTAL VARIABLE REVENUE	$13.0802	kW	17	222	($0.60)		0	222
				4,629,577		**155,000**	**-93,000**	**4,536,577**
Customer Class Name	**2012 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES**							
Residential	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
General Service < 50 kW	$11.3400	19,758	2,688,669	2,906,297	5,594,966	48.06%	51.94%	62.65%
General Service > 50 to 4999 kW	$20.7700	2,456	612,133	598,476	1,210,609	50.56%	49.44%	13.56%
Unmetered Scattered Load	$240.1500	279	804,022	970,586	1,774,608	45.31%	54.69%	19.87%
Street Lighting	$11.3000	61	8,272	11,768	20,040	41.28%	58.72%	0.22%
Sentinel Lighting	$3.8800	6,026	280,571	49,228	329,798	85.07%	14.93%	3.69%
DISTRIBUTION REVENUE	$2.5300	9	273	222	496	55.13%	44.87%	0.01%
			4,393,940	**4,536,577**	**8,930,516**	49.20%	50.80%	100.00%

Westario Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to customers residing in residential dwelling units taking energy at 600 volts or less, with energy generally supplied as single phase, 3-wire, 60 Hertz, having a nominal voltage of 120/240 volts. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.34
Distribution Volumetric Rate	$/kWh	0.0142
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0007
Rate Rider for Tax Adjustments – effective until April 30, 2013	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0015)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0019

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, taking energy at 600 volts or less, requiring a connection with a connected load of less than 50 kW, and including Town Houses and Condominiums that require centralized bulk metering, whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	20.77
Distribution Volumetric Rate	$/kWh	0.0092
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0002
Rate Rider for Tax Adjustments – effective until April 30, 2013	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0015)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Westario Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to general service buildings, defined as buildings that are used for purposes other than single-family dwellings, requiring a connection with a connected load greater than 50 kW but less than 5,000 kW, whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	240.15
Distribution Volumetric Rate	$/kW	2.2373
Low Voltage Service Rate	$/kW	0.3990
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.0244
Rate Rider for Tax Adjustments – effective until April 30, 2013	$/kW	(0.0371)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.5770)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	(0.1048)
Retail Transmission Rate – Network Service Rate	$/kW	1.9887
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6929

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Westario Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 600 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	11.30
Distribution Volumetric Rate	$/kWh	0.0422
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Tax Adjustments – effective until April 30, 2013	$/kWh	(0.0006)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0012)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Westario Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.53
Distribution Volumetric Rate	$/kW	13.0802
Low Voltage Service Rate	$/kW	0.3153
Rate Rider for Tax Adjustments – effective until April 30, 2013	$/kW	(0.2288)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.1627)
Retail Transmission Rate – Network Service Rate	$/kW	1.5096
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5476

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Westario Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	3.88
Distribution Volumetric Rate	$/kW	3.2599
Low Voltage Service Rate	$/kW	0.3079
Rate Rider for Tax Adjustments – effective until April 30, 2013	$/kW	(0.2780)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.8471)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	(0.1653)
Retail Transmission Rate – Network Service Rate	$/kW	1.4976
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5348

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Westario Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Westario Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnect – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service installation and removal – overhead – no transformer	$	500.00
Temporary service installation and removal – underground – no transformer	$	300.00
Temporary service installation and removal – overhead – with transformer	$	1000.00
Specific charge for access to the power poles – per pole/year	$	22.35

Westario Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0205

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0788
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0680

Exhibit 8: Rate Design

Tab 2 (of 4): Proposed Changes to Distribution Rates

OVERVIEW OF FIXED AND VARIABLE CHARGES

Table 1 below shows the proposed monthly service charge for each customer class, the resulting splits of base revenue from fixed and variable charges, and the ensuing usage rates.

Table 1: Fixed to Variable Rate Design

Refresh	Existing Rates (a)			Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximun Fixed Rate (b)		
Customer Class Name	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %
Residential	$11.34	48.64%	51.36%	$5.89	21.31%	78.69%	$17.01	61.54%	38.46%
General Service < 50 kW	$20.77	51.09%	48.91%	$4.45	9.71%	90.29%	$20.77	45.30%	54.70%
General Service > 50 to 4999 k	$240.15	45.34%	54.66%	$31.88	6.94%	93.06%	$240.15	52.27%	47.73%
Unmetered Scattered Load	$11.30	41.62%	58.38%	$1.44	9.53%	90.47%	$11.30	74.78%	25.22%
Street Lighting	$3.88	85.25%	14.75%	($0.08)	-1.58%	101.58%	$7.63	150.83%	-50.83%
Sentinel Lighting	$2.53	55.13%	44.87%	$1.47	17.70%	82.30%	$8.19	98.59%	1.41%

	Existing Fixed/Variable Split (c)			Clear Inout Rate Application			Base Revenue Requirement $		
Customer Class Name	Rate	Fixed %	Variable %	Fixed Rate	Fixed %	Variable %	Total (d)	Fixed (e)	Variable (f)
Residential	$13.45	48.64%	51.36%	$13.45	48.66%	51.34%	6,645,846	3,233,810	3,412,036
General Service < 50 kW	$23.42	51.09%	48.91%	$20.77	45.30%	54.70%	1,359,406	615,872	743,534
General Service > 50 to 4999 k	$208.31	45.34%	54.66%	$208.31	45.34%	54.66%	1,543,837	699,922	843,915
Unmetered Scattered Load	$6.29	41.62%	58.38%	$6.29	41.63%	58.37%	10,879	4,529	6,351
Street Lighting	$4.31	85.25%	14.75%	$4.31	85.20%	14.80%	365,795	311,665	54,130
Sentinel Lighting	$4.58	55.13%	44.87%	$4.58	55.13%	44.87%	897	495	403

	Transf. Allowance ($/kW):		($0.60)	Gross $	Resulting Variable		Existing	Base Revenue $	
Customer Class Name	kW	Rate	Total $ (g)	Variable (h)	Rate (i)	per	Var. Rate (j)	Fixed (k)	Gross (l)
Residential				3,412,036	$0.0168	kWh	$0.0142	3,233,810	6,645,846
General Service < 50 kW				743,534	$0.0116	kWh	$0.0092	615,872	1,359,406
General Service > 50 to 4999 k	155,000	$0.60	93,000	936,915	$1.9666	kW	$2.2373	699,922	1,636,837
Unmetered Scattered Load				6,351	$0.0235	kWh	$0.0422	4,529	10,879
Street Lighting				54,130	$3.6356	kW	$3.2599	311,665	365,795
Sentinel Lighting				403	$23.6800	kW	$13.0802	495	897

With the exception of the GS<50 class, WPI has maintained its existing fixed to variable split. For the General Service< 50 class, maintaining the existing fixed/variable split would result in a rate that exceeded the above maximum boundary indicated in the CA model. WPI deems the proposed fixed to variable split as presented at Table 2 below to be fair and equitable.

Table 2: Final Fixed to Variable Split

Customer Class Name	*Fixed*	*Variable*	*Fixed*	Variable
Residential	49%	51%	13.45	0.0168
General Service < 50 kW	51%	49%	20.77	0.0116
General Service > 50 to 4999 kW	45%	55%	208.31	1.9666
Unmetered Scattered Load	42%	58%	6.29	0.0235
Street Lighting	85%	15%	4.31	3.6356
Sentinel Lights	55%	45%	4.58	23.6800

PROPOSED RATE RIDERS

Table 1 below shows the proposed monthly service charge for each customer class, the resulting splits of base revenue from fixed and variable charges, and the ensuing usage rates.

Table 1: Final Fixed to Variable Split

Rate Description	Bill Det	Res.	GS<50 kW	GS>50 to 4999 kW	USL	Street Lighting	Sentinel Lighting
Smart Meter Disposition Rider	Monthly	0.3400	0.5100	3.0400			
Stranded Meter Rate Rider	Monthly	0.6744	4.1574	1.9666			
DVA	kWh/kW	0.0027	0.0026	0.9068	0.0029	1.5929	3.2891
Global Adjustment	kWh/kW	0.0017	0.0017	0.5984	0.0017	530.7319	
LV Charges	kWh/kW	0.0017	0.0015	0.5697	0.0015	0.4502	0.4397

Exhibit 8: Rate Design

Tab 3 (of 4): Transmission, Low Voltage and Line Losses

RETAIL TRANSMISSION SERVICE RATES (RTSR)

WPI completed its 2013 proposed RTSR in accordance with the Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates, October 22, 2008 (and any subsequent updates). The RTSR model provided by the Board is being filed in conjunction with this application.

Table 1 below presents WPI's proposed RTSR for the Test Year. The proposed rates are reflected in WPI's projected power supply expense for 2013, shown in Exhibit 3, Tab 1, Schedule 4, Attachment 1.

The trend indicates that the current rates result in under-collection of transmission charges for both Network Service and Connection Service. This conclusion is consistent with the accumulation of credit balances in variance accounts 1584-RSVA/NW and 1586-RSVA/CN during the last year period. WPI therefore proposes to adjust its RTSRs to offset the under-collection bias in its existing retail rates.

As an embedded distributor, WPI pays Hydro One Networks Inc. ("HONI") retail transmission service rates for the supply of transmission services, rather than the Uniform Transmission Rates ("UTRs") paid by market participants.

Table 1: Proposed RTSR

Rate Class	Unit	RTSR Network	RTSR Conn.
Residential	kWh	0.0060	0.0021
General Service Less Than 50 kW	kWh	0.0055	0.0019
General Service 50 to 4,999 kW	kW	2.2885	0.7632
Unmetered Scattered Load	kWh	0.0055	0.0019
Sentinel Lighting	kW	1.7372	0.6031
Street Lighting	kW	1.7234	0.5890

Table 2 below shows the realignment of current Network Rates to recover forecasted wholesale network costs.

Table 2 – Adjusted Network to Current WS

	Unit	Current RTSR Network	Loss Adj Billed kWh	Loss Adj Billed kW	Billed Amt	Billed Amt %	Current WS Billing	Adj RTSR Network
Residential	kWh	0.0052	216,474,209	-	1,125,666	52.8%	1,295,390	0.0060
GS Less Than 50 kW	kWh	0.0048	69,225,260	-	332,281	15.6%	382,381	0.0055
GS 50 to 4,999 kW	kW	1.9887	165,591,439	332,399	661,042	31.0%	760,712	2.2885
USL	kWh	0.0048	311,041	-	1,493	0.1%	1,718	0.0055
Sentinel Lighting	kW	1.5096	18,155	21	32	0.0%	37	1.7372
Street Lighting	kW	1.4976	5,433,337	7,793	11,671	0.5%	13,430	1.7234
					2,132,185			

Table 3 below shows the update to Network Rates to recover forecasted wholesale network costs.

Table 3 – Adjusted Network to Forecasted WS

		Adj RTSR Network	Loss Adj Billed kWh	Loss Adj Billed kW	Billed Amt	Billed Amt %	Current WS Billing	Proposed RTSR Network
Residential	kWh	0.0060	216,474,209	0	1,295,390	52.8%	1,295,390	0.0060
GS Less Than 50 kW	kWh	0.0055	69,225,260	0	382,381	15.6%	382,381	0.0055
GS 50 to 4,999 kW	kW	2.2885	165,591,439	332399	760,712	31.0%	760,712	2.2885
USL	kWh	0.0055	311,041	0	1,718	0.1%	1,718	0.0055
Sentinel Lighting	kW	1.7372	18,155	21.255	37	0.0%	37	1.7372
Street Lighting	kW	1.7234	5,433,337	7793	13,430	0.5%	13,430	1.7234
					2,453,669			

Table 4 below shows the realignment of current Connection Rates to recover wholesale connection costs.

Table 4 – Adjusted Connection to Current WS

Adjusted Connection to Current WS		Current RTSR Conn.	Loss Adj Billed kWh	Loss Adj Billed kW	Billed Amt	Billed Amt %	Current WS Billing	Adj RTSR Conn
Residential	kWh	0.0019	216,474,209	0	411,301	53.8%	453,009	0.0021
GS Less Than 50 kW	kWh	0.0017	69,225,260	0	117,683	15.4%	129,616	0.0019
GS 50 to 4,999 kW	kW	0.6929	165,591,439	332399	230,319	30.1%	253,675	0.7632
USL	kWh	0.0017	311,041	0	529	0.1%	582	0.0019
Sentinel Lighting	kW	0.5476	18,155	21.255	12	0.0%	13	0.6031
Street Lighting	kW	0.5348	5,433,337	7793	4,168	0.5%	4,590	0.5890
					764,011			

Table 5 below shows the update to Connection Rates to recover forecasted wholesale connection costs.

Table 5 – Adjusted Connection to Forecasted WS

Adjusted Connection to Forecasted WS		Adj RTSR Conn.	Loss Adj Billed kWh	Loss Adj Billed kW	Billed Amt	Billed Amt %	Current WS Billing	Proposed RTSR Conn
Residential	kWh	0.0021	216,474,209	0	453,009	53.8%	453,009	0.0021
GS Less Than 50 kW	kWh	0.0019	69,225,260	0	129,616	15.4%	129,616	0.0019
GS 50 to 4,999 kW	kW	0.7632	165,591,439	332399	253,675	30.1%	253,675	0.7632
USL	kWh	0.0019	311,041	0	582	0.1%	582	0.0019
Sentinel Lighting	kW	0.6031	18,155	21.255	13	0.0%	13	0.6031
Street Lighting	kW	0.5890	5,433,337	7793	4,590	0.5%	4,590	0.5890
					841,485			

Current, Forecasted and Historical Transmission Costs and Revenues are shown at Attachment 1 of this schedule. UTR's used to calculate the proposed RTSR are presented at Attachment 2 of this schedule.

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Westario Power Inc. - - CoS

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO

Month	Network			Line Connection			Transformation Connection			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

HYDRO ONE

Month	Network			Line Connection			Transformation Connection			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	90,080	$2.65	$ 238,712	62,973	$2.14	$ 134,762	27,245	$1.50	$ 40,868	$ 175,630
February	86,366	$2.65	$ 228,870	59,856	$2.14	$ 128,092	26,510	$1.50	$ 39,765	$ 167,857
March	79,564	$2.65	$ 210,845	54,381	$2.14	$ 116,375	25,183	$1.50	$ 37,775	$ 154,150
April	71,666	$2.65	$ 189,915	45,841	$2.14	$ 98,100	25,825	$1.50	$ 38,738	$ 136,837
May	69,294	$2.65	$ 183,629	42,545	$2.14	$ 91,046	26,749	$1.50	$ 40,124	$ 131,170
June	67,699	$2.65	$ 179,402	41,451	$2.14	$ 88,705	26,248	$1.50	$ 39,372	$ 128,077
July	76,374	$2.65	$ 202,391	47,989	$2.14	$ 102,696	28,385	$1.50	$ 42,578	$ 145,274
August	70,467	$2.65	$ 186,738	44,254	$2.14	$ 94,704	26,213	$1.50	$ 39,320	$ 134,023
September	60,506	$2.65	$ 160,341	38,705	$2.14	$ 82,829	22,552	$1.50	$ 33,828	$ 116,657
October	66,783	$2.65	$ 176,974	43,348	$2.14	$ 92,765	23,435	$1.50	$ 35,153	$ 127,917
November	78,336	$2.65	$ 207,590	52,162	$2.14	$ 111,627	26,174	$1.50	$ 39,261	$ 150,888
December	92,642	$2.65	$ 245,501	59,166	$2.14	$ 126,615	33,476	$1.50	$ 50,214	$ 176,829
Total	909,777	$ 2.65	$ 2,410,908	592,671	$ 2.14	$ 1,268,316	317,995	$ 1.50	$ 476,993	$ 1,745,308

TOTAL

Month	Network			Line Connection			Transformation Connection			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	90,080	$2.65	$ 238,712	62,973	$2.14	$ 134,762	27,245	$1.50	$ 40,868	$ 175,630
February	86,366	$2.65	$ 228,870	59,856	$2.14	$ 128,092	26,510	$1.50	$ 39,765	$ 167,857
March	79,564	$2.65	$ 210,845	54,381	$2.14	$ 116,375	25,183	$1.50	$ 37,775	$ 154,150
April	71,666	$2.65	$ 189,915	45,841	$2.14	$ 98,100	25,825	$1.50	$ 38,738	$ 136,837
May	69,294	$2.65	$ 183,629	42,545	$2.14	$ 91,046	26,749	$1.50	$ 40,124	$ 131,170
June	67,699	$2.65	$ 179,402	41,451	$2.14	$ 88,705	26,248	$1.50	$ 39,372	$ 128,077
July	76,374	$2.65	$ 202,391	47,989	$2.14	$ 102,696	28,385	$1.50	$ 42,578	$ 145,274
August	70,467	$2.65	$ 186,738	44,254	$2.14	$ 94,704	26,213	$1.50	$ 39,320	$ 134,023
September	60,506	$2.65	$ 160,341	38,705	$2.14	$ 82,829	22,552	$1.50	$ 33,828	$ 116,657
October	66,783	$2.65	$ 176,974	43,348	$2.14	$ 92,765	23,435	$1.50	$ 35,153	$ 127,917
November	78,336	$2.65	$ 207,590	52,162	$2.14	$ 111,627	26,174	$1.50	$ 39,261	$ 150,888
December	92,642	$2.65	$ 245,501	59,166	$2.14	$ 126,615	33,476	$1.50	$ 50,214	$ 176,829
Total	909,777	$ 2.65	$ 2,410,908	592,671	$ 2.14	$ 1,268,316	317,995	$ 1.50	$ 476,993	$ 1,745,308

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Westario Power Inc. - - CoS

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
February	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
March	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
April	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
May	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
June	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
July	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
August	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
September	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
October	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
November	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
December	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	90,080	$ 2.6970	$ 242,946	62,973	$ 0.6150	$ 38,728	27,245	$ 1.5000	$ 40,868	$ 79,596
February	86,366	$ 2.6970	$ 232,929	59,856	$ 0.6150	$ 36,811	26,510	$ 1.5000	$ 39,765	$ 76,576
March	79,564	$ 2.6970	$ 214,584	54,381	$ 0.6150	$ 33,444	25,183	$ 1.5000	$ 37,775	$ 71,219
April	71,666	$ 2.6970	$ 193,283	45,841	$ 0.6150	$ 28,192	25,825	$ 1.5000	$ 38,738	$ 66,930
May	69,294	$ 2.6970	$ 186,886	42,545	$ 0.6150	$ 26,165	26,749	$ 1.5000	$ 40,124	$ 66,289
June	67,699	$ 2.6970	$ 182,584	41,451	$ 0.6150	$ 25,492	26,248	$ 1.5000	$ 39,372	$ 64,864
July	76,374	$ 2.6970	$ 205,981	47,989	$ 0.6150	$ 29,513	28,385	$ 1.5000	$ 42,578	$ 72,091
August	70,467	$ 2.6970	$ 190,049	44,254	$ 0.6150	$ 27,216	26,213	$ 1.5000	$ 39,320	$ 66,536
September	60,506	$ 2.6970	$ 163,185	38,705	$ 0.6150	$ 23,804	22,552	$ 1.5000	$ 33,828	$ 57,632
October	66,783	$ 2.6970	$ 180,114	43,348	$ 0.6150	$ 26,659	23,435	$ 1.5000	$ 35,153	$ 61,812
November	78,336	$ 2.6970	$ 211,272	52,162	$ 0.6150	$ 32,080	26,174	$ 1.5000	$ 39,261	$ 71,341
December	92,642	$ 2.6970	$ 249,855	59,166	$ 0.6150	$ 36,387	33,476	$ 1.5000	$ 50,214	$ 86,601
Total	909,777	$ 2.70	$ 2,453,669	592,671	$ 0.62	$ 364,493	317,995	$ 1.50	$ 476,993	$ 841,485

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	90,080	$ 2.70	$ 242,946	62,973	$ 0.62	$ 38,728	27,245	$ 1.50	$ 40,868	$ 79,596
February	86,366	$ 2.70	$ 232,929	59,856	$ 0.62	$ 36,811	26,510	$ 1.50	$ 39,765	$ 76,576
March	79,564	$ 2.70	$ 214,584	54,381	$ 0.62	$ 33,444	25,183	$ 1.50	$ 37,775	$ 71,219
April	71,666	$ 2.70	$ 193,283	45,841	$ 0.62	$ 28,192	25,825	$ 1.50	$ 38,738	$ 66,930
May	69,294	$ 2.70	$ 186,886	42,545	$ 0.62	$ 26,165	26,749	$ 1.50	$ 40,124	$ 66,289
June	67,699	$ 2.70	$ 182,584	41,451	$ 0.62	$ 25,492	26,248	$ 1.50	$ 39,372	$ 64,864
July	76,374	$ 2.70	$ 205,981	47,989	$ 0.62	$ 29,513	28,385	$ 1.50	$ 42,578	$ 72,091
August	70,467	$ 2.70	$ 190,049	44,254	$ 0.62	$ 27,216	26,213	$ 1.50	$ 39,320	$ 66,536
September	60,506	$ 2.70	$ 163,185	38,705	$ 0.62	$ 23,804	22,552	$ 1.50	$ 33,828	$ 57,632
October	66,783	$ 2.70	$ 180,114	43,348	$ 0.62	$ 26,659	23,435	$ 1.50	$ 35,153	$ 61,812
November	78,336	$ 2.70	$ 211,272	52,162	$ 0.62	$ 32,080	26,174	$ 1.50	$ 39,261	$ 71,341
December	92,642	$ 2.70	$ 249,855	59,166	$ 0.62	$ 36,387	33,476	$ 1.50	$ 50,214	$ 86,601
Total	909,777	$ 2.70	$ 2,453,669	592,671	$ 0.62	$ 364,493	317,995	$ 1.50	$ 476,993	$ 841,485

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Westario Power Inc. - - CoS

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
February	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
March	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
April	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
May	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
June	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
July	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
August	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
September	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
October	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
November	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
December	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	90,080	$ 2.6970	$ 242,946	62,973	$ 0.6150	$ 38,728	27,245	$ 1.5000	$ 40,868	$ 79,596
February	86,366	$ 2.6970	$ 232,929	59,856	$ 0.6150	$ 36,811	26,510	$ 1.5000	$ 39,765	$ 76,576
March	79,564	$ 2.6970	$ 214,584	54,381	$ 0.6150	$ 33,444	25,183	$ 1.5000	$ 37,775	$ 71,219
April	71,666	$ 2.6970	$ 193,283	45,841	$ 0.6150	$ 28,192	25,825	$ 1.5000	$ 38,738	$ 66,930
May	69,294	$ 2.6970	$ 186,886	42,545	$ 0.6150	$ 26,165	26,749	$ 1.5000	$ 40,124	$ 66,289
June	67,699	$ 2.6970	$ 182,584	41,451	$ 0.6150	$ 25,492	26,248	$ 1.5000	$ 39,372	$ 64,864
July	76,374	$ 2.6970	$ 205,981	47,989	$ 0.6150	$ 29,513	28,385	$ 1.5000	$ 42,578	$ 72,091
August	70,467	$ 2.6970	$ 190,049	44,254	$ 0.6150	$ 27,216	26,213	$ 1.5000	$ 39,320	$ 66,536
September	60,506	$ 2.6970	$ 163,185	38,705	$ 0.6150	$ 23,804	22,552	$ 1.5000	$ 33,828	$ 57,632
October	66,783	$ 2.6970	$ 180,114	43,348	$ 0.6150	$ 26,659	23,435	$ 1.5000	$ 35,153	$ 61,812
November	78,336	$ 2.6970	$ 211,272	52,162	$ 0.6150	$ 32,080	26,174	$ 1.5000	$ 39,261	$ 71,341
December	92,642	$ 2.6970	$ 249,855	59,166	$ 0.6150	$ 36,387	33,476	$ 1.5000	$ 50,214	$ 86,601
Total	909,777	$ 2.70	$ 2,453,669	592,671	$ 0.62	$ 364,493	317,995	$ 1.50	$ 476,993	$ 841,485

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	90,080	$ 2.70	$ 242,946	62,973	$ 0.62	$ 38,728	27,245	$ 1.50	$ 40,868	$ 79,596
February	86,366	$ 2.70	$ 232,929	59,856	$ 0.62	$ 36,811	26,510	$ 1.50	$ 39,765	$ 76,576
March	79,564	$ 2.70	$ 214,584	54,381	$ 0.62	$ 33,444	25,183	$ 1.50	$ 37,775	$ 71,219
April	71,666	$ 2.70	$ 193,283	45,841	$ 0.62	$ 28,192	25,825	$ 1.50	$ 38,738	$ 66,930
May	69,294	$ 2.70	$ 186,886	42,545	$ 0.62	$ 26,165	26,749	$ 1.50	$ 40,124	$ 66,289
June	67,699	$ 2.70	$ 182,584	41,451	$ 0.62	$ 25,492	26,248	$ 1.50	$ 39,372	$ 64,864
July	76,374	$ 2.70	$ 205,981	47,989	$ 0.62	$ 29,513	28,385	$ 1.50	$ 42,578	$ 72,091
August	70,467	$ 2.70	$ 190,049	44,254	$ 0.62	$ 27,216	26,213	$ 1.50	$ 39,320	$ 66,536
September	60,506	$ 2.70	$ 163,185	38,705	$ 0.62	$ 23,804	22,552	$ 1.50	$ 33,828	$ 57,632
October	66,783	$ 2.70	$ 180,114	43,348	$ 0.62	$ 26,659	23,435	$ 1.50	$ 35,153	$ 61,812
November	78,336	$ 2.70	$ 211,272	52,162	$ 0.62	$ 32,080	26,174	$ 1.50	$ 39,261	$ 71,341
December	92,642	$ 2.70	$ 249,855	59,166	$ 0.62	$ 36,387	33,476	$ 1.50	$ 50,214	$ 86,601
Total	909,777	$ 2.70	$ 2,453,669	592,671	$ 0.62	$ 364,493	317,995	$ 1.50	$ 476,993	$ 841,485

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Westario Power Inc. - - CoS

Uniform Transmission Rates

Rate Description	Unit	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate	Effective January 1, 2013 Rate
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.57
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.80
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.86

Hydro One Sub-Transmission Rates

Rate Description	Unit	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate	Effective January 1, 2013 Rate
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A

Rate Description	Unit	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate	Effective January 1, 2013 Rate
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ 0.0470	$ 0.0470
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	-$ 0.0250	-$ 0.0250
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ 0.0580	$ 0.0580
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	-$ 0.0750	-$ 0.0750
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ 0.0050	$ 0.0050

OTHER CHARGES

Retail Service Charges

WPI is proposing to maintain its existing retail service charges which are consistent with the OEB's Standard Rates. The retail service charges are as follows:

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Wholesale Market Service Charges

WPI is proposing to maintain its existing Wholesale Market Service Charges. The proposed rate remains at $0.0052

Rural Rate Protection Charge

WPI is proposing to maintain its existing Rural Rate Protection Charge. The proposed rate remains at $0.0011

Specific Service Charge

WPI anticipates no material changes to the following Specific Service Charge revenue and proposes to maintain the current rates for the following:

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnect – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service installation and removal – overhead – no transformer	$	500.00
Temporary service installation and removal – underground – no transformer	$	300.00
Temporary service installation and removal – overhead – with transformer	$	1000.00
Specific charge for access to the power poles – per pole/year	$	22.35

LOW VOLTAGE CHARGES

Table 1 presents the derivation of proposed retail rates for Low Voltage (“LV”) service. The 2012 estimate of total LV charges was allocated to customer classes, according to each class’ share of projected Transmission-Connection revenue, in accordance with Board policy. The resulting allocated LV charges for each class were divided by the applicable 2013 volumes from the load forecast, as presented in Exhibit 3, Tab 1, Schedule 1, Attachment 1.

Current LV revenues are recovered through a separate rate adder and therefore are not embedded within the approved Distribution Volumetric rate. 2013 LV rates appear on a distinct line item on the proposed schedule of rates (Exhibit 8, Tab 4, Schedule 3, Attachment 1).

The proposed rates are reflected in WPI’s projected power supply expense for 2013, shown in Exhibit 3, Tab 1, Schedule 4, Attachment 1.

Table 1 – Low Voltage Charges

	2012 Low Voltage Rates	
Customer Class Name	Rate	per
Residential	0.0012	kWh
General Service < 50 kW	0.0011	kWh
General Service > 50 to 4999 kW	0.3990	kW
Unmetered Scattered Load	0.0011	kWh
Street Lighting	0.3079	kW
Sentinel Lighting	0.3153	kW

	2013 PROJECTED TRANSMISSION-CONNECTION REVENUE				
Customer Class Name	Rate	per	Volume [1]	Revenue	%
Residential	0.0021	kWh	216,901,778	455,494	48%
General Service < 50 kW	0.0019	kWh	68,574,552	130,292	14%
General Service > 50 to 4999 kW	0.7632	kW	476,416	363,601	38%
Unmetered Scattered Load	0.0019	kWh	289,373	550	0%
Street Lighting	0.6031	kW	14,889	8,980	1%
Sentinel Lighting	0.589	kW	17	10	0%
TOTAL				958,925	100%

	2013 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	% Allocation	Charges	Volume [2]	**Rate**	per
Residential	48%	340,000	202,711,942	**0.0017**	kWh
General Service < 50 kW	14%	97,255	64,088,366	**0.0015**	kWh
General Service > 50 to 4999 kW	38%	271,407	476,416	**0.5697**	kW
Unmetered Scattered Load	0%	410	270,442	**0.0015**	kWh
Street Lighting	1%	6,703	14,889	**0.4502**	kW
Sentinel Lighting	0%	7	17	**0.4397**	kW
TOTAL		715,784			

LOSS ADJUSTMENT FACTORS

Attachment 1 to this schedule presents the determination of WPI's loss adjustment factor.

WPI proposes a Total Loss Factor ("TLF") 1.0700, using the historical average of the last five years as presented at Table 1. The proposed TLF represents a decrease from WPI's currently approved TLF of 1.0788.

WPI is an embedded distributor with Hydro One Networks Inc. ("HONI") as its host distributor. WPI's main service areas are non-contiguous. WPI is connected to the Ontario power transmission grid at four (4) transformer stations which are owned by Hydro One (HO). WPI customers are supplied via seven (7) 44kv feeder circuits which feed 27 WPI owned Sub-Stations.

As reflected in Attachment 1 (Appendix 2-R, Loss Factor) the total losses in WPI's distribution system are only 1.04 while the supply facility loss represents 1.03. WPI is committed to continuing its effort to minimize its distribution system losses.

File Number:	EB2012-0176
Exhibit:	8
Tab:	3
Schedule:	4
Page:	1
Date:	09-Oct-12

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2007	**2008**	**2009**	**2010**	**2011**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	470,987,375	468,419,525	482,358,097	470,860,971	471,627,001	472850593.8
A(2)	"Wholesale" kWh delivered to distributor (lower value)	459,504,027	454,616,955	468,534,412	457,120,491	458,002,862	459555749.4
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	459504027	454616955	468534412	457120491	458002862	459555749.4
D	"Retail" kWh delivered by distributor	438,284,554	445,385,739	445,824,184	445,211,913	434,957,196	441932717.1
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						0
F	Net "Retail" kWh delivered by distributor = **D - E**	438284553.9	444257509.9	446170528.9	445211912.6	434957195.9	441932717.1
G	Loss Factor in Distributor's system = **C / F**	1.048414832	1.023318559	1.050124071	1.026748113	1.052983756	1.039877184
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.024990745	1.030360878	1.029504098	1.03005877	1.029746843	1.028932267
	Total Losses						
I	Total Loss Factor = **G x H**	1.0746155	1.054387409	1.081107034	1.057610898	1.084306699	1.069963188

Notes

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to an actual or virtual meter at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

Exhibit 8: Rate Design

Tab 4 (of 4): Rate Schedules and Bill Impacts

BASE REVENUE CALCULATIONS AND RECONCILIATIONS

The calculation of base revenue by customer class under current rates was presented in Exhibit 8, Tab 1, Schedule 1, Attachment 1.

Table 1 below shows that the sum of revenues allocated to each class corresponds to the total revenue required for the base revenue requirement.

The Attachment also shows that the revenues calculated for each customer class correspond to the allocated amount, with any differences due entirely to rounding.

Attachment 1 of this schedule presents Appendix 2-V Revenue Reconciliation.

Table 1: Reconciliation of Proposed Revenue Requirement

		Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges	
Customer Class Name	Rate	Volume	Revenue	Rate	Volume	Revenue	Calculated *	Allocated **	Difference
Residential	$13.45	240,432	3,233,810	$0.0168	202,711,942	3,405,561	6,639,371	6,645,846	-6,475
GS < 50 kW	$20.77	29,652	615,872	$0.0116	64,088,366	743,425	1,359,297	1,359,406	-109
GS > 50 to 4999 kW	$208.31	3,360	699,922	$1.9666	476,416	936,920	1,636,841	1,636,837	4
USL	$6.29	720	4,529	$0.0235	270,442	6,355	10,884	10,879	5
Street Lighting	$4.31	72,312	311,665	$3.6356	14,889	54,130	365,795	365,795	0
Sentinel Lighting	$4.58	108	495	$23.6800	17	403	897	897	0
TOTAL			4,866,292			5,146,794	10,013,086	10,019,660	-6,574

File Number:	EB2012-0176
Exhibit:	8
Tab:	4
Schedule:	1
Page:	2
Date:	09-Oct-12

Appendix 2-V
Revenue Reconciliation

Rate Class	**Customers/ Connections**	**Number of Customers/Connections**			**Test Year Consumption**		**Proposed Rates**			**Revenues at Proposed Rates**	**Class Specific Revenue Requirement**	**Transformer Allowance Credit**	**Total**	**Difference**
		Start of Test Year	**End of Test Year**	**Average**	**kWh**	**kW**	**Monthly Service Charge**	**Volumetric**						
								kWh	kW					
Residential	Customers			20,036.00	202,711,942		$ 13.45	$ 0.0168		$ 6,639,371.03	$ 6,645,846		$ 6,645,846	$ 6,475
GS < 50 kW	Customers			2,471.00	64,088,366		$ 20.77	$ 0.0116		$ 1,359,297.09	$ 1,359,406		$ 1,359,406	$ 109
GS > 50 to 4,999 kW	Customers			280.00	168,781,699	476,416	$ 208.31		$ 1.9666	$ 1,636,841.31	$ 1,543,837	$ 93,000	$ 1,636,837	-$ 4
Large Use				-						$ -			$ -	$ -
Streetlighting	Connections			6,026.00	5,355,530	14,889	$ 4.31		$ 3.6356	$ 365,795.17	$ 365,795		$ 365,795	-$ 0
Sentinel Lighting	Connections			9.00	17,900	17	$ 4.58		$ 23.6800	$ 897.20	$ 897		$ 897	-$ 0
Unmetered Scattered Load	Customers			60.00	270,442		$ 6.29	$ 0.0235		$ 10,884.19	$ 10,879		$ 10,879	-$ 5
Standby Power				-						$ -			$ -	$ -
Embedded Distributor Class				-						$ -			$ -	$ -
etc.				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$ 10,013,085.97	$ 9,926,660	$ 93,000	$ 10,019,660	$ 6,574

Note

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement

PROPOSED CHANGES TO CONDITIONS OF SERVICE

WPI is planning a comprehensive review of its Conditions of Service in 2013. This review and revision is required to ensure continued compliance with the Distribution System Code or other regulatory requirements.

RATE CHANGES AND BILL IMPACTS

Attachment 1 presents the proposed rates to appear on the draft rate order. For each customer class, the following rates appear:

Service Charge	Includes the fixed monthly service charge in base revenue (Exhibit 8, Tab 2, Schedule 1)
Distribution Volumetric Rate	The variable charge rate (Exhibit 8, Tab 2, Schedule 1)
Low Voltage Service Rate	see Exhibit 8, Tab 3, Schedule 3
Deferral Account Rate Rider	see Exhibit 9, Tab 2, Schedule 2, Attachment 3
Global Adjustment Rate Rider	see Exhibit 9, Tab 2, Schedule 2, Attachment 3
Transmission- Connection	see Exhibit 8, Tab 3, Schedule 1
Transmission- Network	see Exhibit 8, Tab 3, Schedule 1
Wholesale Market Service	no change proposed
Rural Rate Protection Charge	no change proposed
Standard Supply Service	no change proposed

WPI proposes to retain the same Specific Service Charges and Allowances, with no rate changes.

The Total Loss Factors are presented in Exhibit 8, Tab 3, Schedule 4 Attachment 1.

Attachment 2 presents detailed sample bill impacts, comparing monthly customer bills under the existing (2012) rates to the proposed (2013) rates. The following pages show the line item details for each sample bill.

Total bill impacts vary by customer class, ranging from a decrease of 15.42% for Unmetered Scattered Load (“USL”) to an increase of 21.27% for Sentinel Lighting.

While base distribution rates would increase in each customer class to address the revenue deficiency, and retail transmission service rates would also increase due to increased supply rates, these increases would be partially offset by a lower line loss factor for commodity based charges.

Sentinel Lighting and Street Lighting are the only customer class facing a total bill impact in excess of 10%. The increase in Sentinel Lighting is limited to only 9 connections and accounts for only $900 of the utilities revenues. While the increase in Street Lighting rates is approximately 12.26%; the total amount is $8.40 which is in line with the proposed increase in the residential rate category.

Under these circumstances, WPI does not propose any further measures to mitigate bill impacts for either customer class.

WPI respectfully submits that its proposed rates are reasonable and well in line with other utilities of roughly the same size (customer count/revenue requirement). The table below uses data published by the OEB on September 27, 2012[1] for comparison purposes.

The numbers in the chart have been calculated using the following data and assumptions:

- shows estimated total bill impacts for those utilities with 2012 distribution rates
- a residential consumer using 800 kilowatt hours per month
- loss factor adjustment has been applied
- a consumer who is on the RPP, purchasing their electricity through their utility.

Cohort	Delivery Charge
Collus	$26.73
Festival	$35.55
Innisfil	$43.59

1 http://www.ontarioenergyboard.ca/OEB/_Documents/2012EDR/bill_impacts_2012.pdf

Norfolk	$49.50
NorthBay	$36.29
St-Thomas	$28.85
Welland	$37.77
Woodstock	$41.05
Westario	$28.91
2012 Average	$36.47
Westario 2013 Proposed Delivery Charge	**$38.36**

A large portion of WPI's bill impacts can be attributed to Rate Riders which are for the most part related to either government mandated costs or spending (i.e. smart meters), or Pass-through Charges (i.e. DVA and LV Charges) which WPI considers to be beyond the utility's control. For illustrative purposes, WPI provides a table below which removes its rate riders from its bill impact and in order to isolate the total bill impact of the distribution rate changes. As can be seen, the bill impact drops from 8.43% to 4.18%.

WPI needs the proposed rates to remain in compliance with its regulators and meet its mandate and commitment to provide safe, reliable cost-effective services and products achieving sustainable growth while respecting the community and the environment.

Customer Class: **Residential**

Consumption 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	per kWh	$ 11.3400	1	$ 11.34	$ 13.4500	1	$ 13.45	$ 2.11	18.61%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
SMDR	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0142	800	$ 11.36	$ 0.0168	800	$ 13.44	$ 2.08	18.31%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		800	$ -		800	$ -	$ -	
Rate Rider for Tax Adjustments	per kWh		800	$ -		800	$ -	$ -	
	per kWh		800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 22.70			$ 26.89	**$ 4.19**	**18.46%**
Deferral/Variance Account Disposition Rate Rider	per kWh		800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge			800	$ -		800	$ -	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.70**			**$ 26.89**	**$ 4.19**	**18.46%**
RTSR - Network	per kWh	$ 0.0052	863	$ 4.49	$ 0.0060	856	$ 5.14	$ 0.65	14.44%
RTSR - Line and Transformation Connection	per kWh	$ 0.0019	863	$ 1.64	$ 0.0021	856	$ 1.80	$ 0.16	9.62%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28.83**			**$ 33.82**	**$ 5.00**	**17.33%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	863	$ 4.49	$ 0.0052	856	$ 4.45	-$ 0.04	-0.82%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	863	$ 0.95	$ 0.0011	856	$ 0.94	-$ 0.01	-0.82%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	863	$ 0.60	$ 0.0007	856	$ 0.60	-$ 0.00	-0.82%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	263	$ 23.15	$ 0.0880	256	$ 22.53	-$ 0.62	-2.68%
TOU - Off Peak	per kWh	$ 0.0650	552	$ 35.90	$ 0.0650	548	$ 35.61	-$ 0.29	-0.82%
TOU - Mid Peak	per kWh	$ 0.1000	155	$ 15.53	$ 0.1000	154	$ 15.41	-$ 0.13	-0.82%
TOU - On Peak	per kWh	$ 0.1170	155	$ 18.18	$ 0.1170	154	$ 18.03	-$ 0.15	-0.82%
Total Bill on RPP (before Taxes)				**$ 103.27**			**$ 107.59**	**$ 4.33**	**4.19%**
HST		13%		$ 13.42	13%		$ 13.99	$ 0.56	4.19%
Total Bill (including HST)				$ 116.69			$ 121.58	$ 4.89	4.19%
Ontario Clean Energy Benefit [1]				-$ 11.67			-$ 12.16	-$ 0.49	4.20%
Total Bill on RPP (including OCEB)				**$ 105.02**			**$ 109.42**	**$ 4.40**	**4.19%**
Total Bill on TOU (before Taxes)				**$ 104.73**			**$ 109.11**	**$ 4.38**	**4.18%**
HST		13%		$ 13.62	13%		$ 14.18	$ 0.57	4.18%
Total Bill (including HST)				$ 118.35			$ 123.29	$ 4.95	4.18%
Ontario Clean Energy Benefit [1]				-$ 11.83			-$ 12.33	-$ 0.50	4.23%
Total Bill on TOU (including OCEB)				**$ 106.52**			**$ 110.96**	**$ 4.45**	**4.18%**

Loss Factor (%) Current: 7.88% Proposed: 7.00%

Tariff of Proposed Rates and Charges

Residential

		May 1/13
Service Charge	$	13.45
Distribution Volumetric Rate	$/kWh	0.0168
Rate Rider for Global Adjusment Sub-Account (Applicable only to Non-RPP customers)	$/kWh	0.0017
Rate Rider for Deferral/Variance Account Disposition	$/kWh	0.0027
Smart Meter Disposition Rider	$	0.3400
Stranded Meter Rate Rider	$	0.6744
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0021
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Low Voltage Service Rate	$/kWh	0.0017
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service < 50 kW

Service Charge	$	20.77
Distribution Volumetric Rate	$/kWh	0.0116
Rate Rider for Global Adjusment Sub-Account (Applicable only to Non-RPP customers)	$/kWh	0.0017
Rate Rider for Deferral/Variance Account Disposition	$/kWh	0.0026
Smart Meter Disposition Rider	$	0.5100
Stranded Meter Rate Rider	$	4.1574
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0019
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Low Voltage Service Rate	$/kWh	0.0015
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service > 50 to 4999 kW

Service Charge	$	208.31
Distribution Volumetric Rate	$/kW	1.9666
Rate Rider for Global Adjusment Sub-Account (Applicable only to Non-RPP customers)	$/kW	0.5984
Rate Rider for Deferral/Variance Account Disposition	$/kW	0.9068
Smart Meter Disposition Rider	$	3.0400
Stranded Meter Rate Rider	$	
Retail Transmission Rate – Network Service Rate	$/kW	2.2885
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7632
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Low Voltage Service Rate	$/kW	0.5697
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge	$	6.2900
Distribution Volumetric Rate	$/kWh	0.0235
Rate Rider for Global Adjusment Sub-Account (Applicable only to Non-RPP customers)	$/kWh	0.0017
Rate Rider for Deferral/Variance Account Disposition	$/kWh	0.0029
Smart Meter Disposition Rider	$	
Stranded Meter Rate Rider	$	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0019
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Low Voltage Service Rate	$/kWh	0.0015
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	4.58
Distribution Volumetric Rate	$/kW	23.68
Rate Rider for Global Adjusment Sub-Account (Applicable only to Non-RPP customers)	$/kW	
Rate Rider for Deferral/Variance Account Disposition	$/kW	3.2891
Smart Meter Disposition Rider	$	
Stranded Meter Rate Rider	$	
Retail Transmission Rate – Network Service Rate	$/kW	1.7234
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5890
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Low Voltage Service Rate	$/kW	0.4397
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	4.31
Distribution Volumetric Rate	$/kW	3.6356
Rate Rider for Global Adjusment Sub-Account (Applicable only to Non-RPP customers)	$/kW	0.5975
Rate Rider for Deferral/Variance Account Disposition	$/kW	1.5929
Smart Meter Disposition Rider	$	
Stranded Meter Rate Rider	$	
Retail Transmission Rate – Network Service Rate	$/kW	1.7372
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6031
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Low Voltage Service Rate	$/kW	0.4502
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT Generator Service

Service Charge	$	5.25

Specific Service Charges

Arrears Certificate	$	15
Statement of Account	$	15
Pulling post-dated cheques	$	15
Duplicate invoices for previous billing	$	15
Request for other billing information	$	15
Easement Letter	$	15
Income tax letter	$	15
Notification Charge	$	15
Account history	$	15
Credit reference/credit check (plus credit agency costs)	$	15
Returned Cheque charge (plus bank charges)	$	15
Charge to certify cheque	$	15
Legal letter charge	$	15
Account set up charge / change of occupancy charge	$	30
Special Meter reads	$	30
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30
Late Payment - per month	%	1.5
Disconnect/Reconnect at meter – during regular hours	$	65
Disconnect/Reconnect at meter – after regular hours	$	185
Disconnect/Reconnect at pole – during regular hours	$	185
Disconnect/Reconnect at pole – after regular hours	$	415
Install / remove load control device – during regular hours	$	65
Install / remove load control device – after regular hours	$	185
Service call – customer-owned equipment	$	30
Service call – after regular hours	$	165
Temporary service install and remove – overhead – no transformer	$	500
Temporary service install and remove – underground – no transformer	$	300
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	0.6
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	

LOSS FACTORS

Secondary Metered Customer	1.07

File Number:	EB2012-0176
Exhibit:	8
Tab:	4
Schedule:	3
Appendix:	2
Page:	1
Date:	9-Oct-12

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	per kWh	$ 11.3400	1	$ 11.34	$ 13.4500	1	$ 13.45	$ 2.11	18.61%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
SMDR	Monthly		1	$ -	$ 0.3400	1	$ 0.34	$ 0.34	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.6744	1	$ 0.67	$ 0.67	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0142	800	$ 11.36	$ 0.0168	800	$ 13.44	$ 2.08	18.31%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	800	$ 0.56		800	$ -	-$ 0.56	-100.00%
Rate Rider for Tax Adjustments	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
	per kWh		800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 23.02			$ 27.90	**$ 4.88**	**21.22%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0015	800	-$ 1.20	$ 0.0027	800	$ 2.16	$ 3.36	-280.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge		$ 0.0012	800	$ 0.96	$ 0.0017	800	$ 1.36	$ 0.40	41.67%
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.78**			**$ 31.42**	**$ 8.64**	**37.95%**
RTSR - Network	per kWh	$ 0.0052	863	$ 4.49	$ 0.0060	856	$ 5.14	$ 0.65	14.44%
RTSR - Line and Transformation Connection	per kWh	$ 0.0019	863	$ 1.64	$ 0.0021	856	$ 1.80	$ 0.16	9.62%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28.91**			**$ 38.36**	**$ 9.45**	**32.69%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	863	$ 4.49	$ 0.0052	856	$ 4.45	-$ 0.04	-0.82%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	863	$ 0.95	$ 0.0011	856	$ 0.94	-$ 0.01	-0.82%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	863	$ 0.60	$ 0.0007	856	$ 0.60	-$ 0.00	-0.82%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	263	$ 23.15	$ 0.0880	256	$ 22.53	-$ 0.62	-2.68%
TOU - Off Peak	per kWh	$ 0.0650	552	$ 35.90	$ 0.0650	548	$ 35.61	-$ 0.29	-0.82%
TOU - Mid Peak	per kWh	$ 0.1000	155	$ 15.53	$ 0.1000	154	$ 15.41	-$ 0.13	-0.82%
TOU - On Peak	per kWh	$ 0.1170	155	$ 18.18	$ 0.1170	154	$ 18.03	-$ 0.15	-0.82%
Total Bill on RPP (before Taxes)				**$ 103.35**			**$ 112.13**	**$ 8.78**	**8.50%**
HST		13%		$ 13.44	13%		$ 14.58	$ 1.14	8.50%
Total Bill (including HST)				$ 116.78			$ 126.70	$ 9.92	8.50%
Ontario Clean Energy Benefit [1]				-$ 11.68			-$ 12.67	-$ 0.99	8.48%
Total Bill on RPP (including OCEB)				**$ 105.10**			**$ 114.03**	**$ 8.93**	**8.50%**
Total Bill on TOU (before Taxes)				**$ 104.81**			**$ 113.64**	**$ 8.83**	**8.43%**
HST		13%		$ 13.63	13%		$ 14.77	$ 1.15	8.43%
Total Bill (including HST)				$ 118.44			$ 128.42	$ 9.98	8.43%
Ontario Clean Energy Benefit [1]				-$ 11.84			-$ 12.84	-$ 1.00	8.45%
Total Bill on TOU (including OCEB)				**$ 106.60**			**$ 115.58**	**$ 8.98**	**8.43%**
Loss Factor (%)		7.88%			7.00%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB2012-0176
Exhibit:	8
Tab:	4
Schedule:	3
Appendix:	2
Page:	2
Date:	9-Oct-12

Appendix 2-W
Bill Impacts

Customer Class: **GS<50**

Consumption 2000 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	per kWh	$ 20.7700	1	$ 20.77	$ 20.7700	1	$ 20.77	$ -	0.00%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
SMDR	Monthly		1	$ -	$ 0.5100	1	$ 0.51	$ 0.51	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.1574	1	$ 4.16	$ 4.16	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0092	2000	$ 18.40	$ 0.0116	2000	$ 23.20	$ 4.80	26.09%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40		2000	$ -	-$ 0.40	-100.00%
Rate Rider for Tax Adjustments	per kWh	-$ 0.0002	2000	-$ 0.40		2000	$ -	$ 0.40	-100.00%
	per kWh		2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 39.17			$ 48.64	**$ 9.47**	**24.17%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0015	2000	-$ 3.00	$ 0.0026	2000	$ 5.20	$ 8.20	-273.33%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge		$ 0.0011	2000	$ 2.20	$ 0.0015	2000	$ 3.00	$ 0.80	36.36%
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 38.37**			**$ 56.84**	**$ 18.47**	**48.13%**
RTSR - Network	per kWh	$ 0.0048	2158	$ 10.36	$ 0.0055	2140	$ 11.77	$ 1.41	13.65%
RTSR - Line and Transformation Connection	per kWh	$ 0.0017	2158	$ 3.67	$ 0.0019	2140	$ 4.07	$ 0.40	10.85%
Sub-Total C - Delivery (including Sub-Total B)				**$ 52.39**			**$ 72.67**	**$ 20.28**	**38.70%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2158	$ 11.22	$ 0.0052	2140	$ 11.13	-$ 0.09	-0.82%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2158	$ 2.37	$ 0.0011	2140	$ 2.35	-$ 0.02	-0.82%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	2158	$ 1.51	$ 0.0007	2140	$ 1.50	-$ 0.01	-0.82%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1558	$ 137.07	$ 0.0880	1540	$ 135.52	-$ 1.55	-1.13%
TOU - Off Peak	per kWh	$ 0.0650	1381	$ 89.76	$ 0.0650	1370	$ 89.02	-$ 0.73	-0.82%
TOU - Mid Peak	per kWh	$ 0.1000	388	$ 38.84	$ 0.1000	385	$ 38.52	-$ 0.32	-0.82%
TOU - On Peak	per kWh	$ 0.1170	388	$ 45.44	$ 0.1170	385	$ 45.07	-$ 0.37	-0.82%
Total Bill on RPP (before Taxes)				**$ 249.82**			**$ 268.42**	**$ 18.61**	**7.45%**
HST		13%		$ 32.48	13%		$ 34.90	$ 2.42	7.45%
Total Bill (including HST)				$ 282.29			$ 303.32	$ 21.03	7.45%
Ontario Clean Energy Benefit [1]				-$ 28.23			-$ 30.33	-$ 2.10	7.44%
Total Bill on RPP (including OCEB)				**$ 254.06**			**$ 272.99**	**$ 18.93**	**7.45%**
Total Bill on TOU (before Taxes)				**$ 241.78**			**$ 260.52**	**$ 18.74**	**7.75%**
HST		13%		$ 31.43	13%		$ 33.87	$ 2.44	7.75%
Total Bill (including HST)				$ 273.21			$ 294.38	$ 21.17	7.75%
Ontario Clean Energy Benefit [1]				-$ 27.32			-$ 29.44	-$ 2.12	7.76%
Total Bill on TOU (including OCEB)				**$ 245.89**			**$ 264.94**	**$ 19.05**	**7.75%**

Loss Factor (%) 7.88% 7.00%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB2012-0176
Exhibit:	8
Tab:	4
Schedule:	3
Appendix:	2
Page:	3
Date:	9-Oct-12

Appendix 2-W
Bill Impacts

Customer Class: **GS 50 to 4,999 kW**

Consumption 50000 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
140 **KW**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 240.1500	1	$ 240.15	$ 208.3100	1	$ 208.31	-$ 31.84	-13.26%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
SMDR	Monthly		1	$ -	$ 3.0400	1	$ 3.04	$ 3.04	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.2373	140	$ 313.22	$ 1.9666	140	$ 275.32	-$ 37.90	-12.10%
Smart Meter Disposition Rider			140	$ -		140	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0244	140	$ 3.42		140	$ -	-$ 3.42	-100.00%
Rate Rider for Tax Adjustments	per kW	-$ 0.0371	140	-$ 5.19		140	$ -	$ 5.19	-100.00%
	per kWh		140	$ -		140	$ -	$ -	
			140	$ -		140	$ -	$ -	
			140	$ -		140	$ -	$ -	
			140	$ -		140	$ -	$ -	
			140	$ -		140	$ -	$ -	
			140	$ -		140	$ -	$ -	
Sub-Total A				$ 551.59			$ 486.67	**-$ 64.92**	**-11.77%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5770	140	-$ 80.78	$ 0.9068	140	$ 126.95	$ 207.73	-257.16%
Global Adjustment Rate Rider	per kW	-$ 0.1048	140	-$ 14.67	$ 0.5984	140	$ 83.78	$ 98.45	-670.99%
			140	$ -		140	$ -	$ -	
			140	$ -		140	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.3990	140	$ 55.86	$ 0.5697	140	$ 79.76	$ 23.90	42.78%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 512.00**			**$ 777.16**	**$ 265.16**	**51.79%**
RTSR - Network	per kW	$ 1.9887	140	$ 278.42	$ 2.2885	140	$ 320.39	$ 41.97	15.08%
RTSR - Line and Transformation Connection	per kW	$ 0.6929	140	$ 97.01	$ 0.7632	140	$ 106.85	$ 9.84	10.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 887.43**			**$ 1,204.40**	**$ 316.97**	**35.72%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	50000	$ 260.00	$ 0.0052	50000	$ 260.00	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	50000	$ 55.00	$ 0.0011	50000	$ 55.00	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	50000	$ 35.00	$ 0.0007	50000	$ 35.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	53340	$ 4,693.92	$ 0.0880	53340	$ 4,693.92	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	34522	$ 2,243.90	$ 0.0650	34521.6	$ 2,243.90	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1000	9709	$ 970.92	$ 0.1000	9709.2	$ 970.92	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1170	9709	$ 1,135.98	$ 0.1170	9709.2	$ 1,135.98	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 5,976.60**			**$ 6,293.57**	**$ 316.97**	**5.30%**
HST		13%		$ 776.96	13%		$ 818.16	$ 41.21	5.30%
Total Bill (including HST)				$ 6,753.55			$ 7,111.73	$ 358.18	5.30%
Ontario Clean Energy Benefit [1]				-$ 675.36			-$ 711.17	-$ 35.81	5.30%
Total Bill on RPP (including OCEB)				**$ 6,078.19**			**$ 6,400.56**	**$ 322.37**	**5.30%**
Total Bill on TOU (before Taxes)				**$ 5,588.48**			**$ 5,905.45**	**$ 316.97**	**5.67%**
HST		13%		$ 726.50	13%		$ 767.71	$ 41.21	5.67%
Total Bill (including HST)				$ 6,314.98			$ 6,673.16	$ 358.18	5.67%
Ontario Clean Energy Benefit [1]				-$ 631.50			-$ 667.32	-$ 35.82	5.67%
Total Bill on TOU (including OCEB)				**$ 5,683.48**			**$ 6,005.84**	**$ 322.36**	**5.67%**

Loss Factor (%) 7.88% 7.00%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB2012-0176
Exhibit:	8
Tab:	4
Schedule:	3
Appendix:	2
Page:	4
Date:	9-Oct-12

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 375 **kWh** (●) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	per kWh	$ 11.3000	1	$ 11.30	$ 6.2900	1	$ 6.29	-$ 5.01	-44.34%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
SMDR	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0422	375	$ 15.83	$ 0.0235	375	$ 8.81	-$ 7.01	-44.31%
Smart Meter Disposition Rider			375	$ -		375	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		375	$ -		375	$ -	$ -	
Rate Rider for Tax Adjustments	per kWh	-$ 0.0006	375	-$ 0.23		375	$ -	$ 0.23	-100.00%
	per kWh		375	$ -		375	$ -	$ -	
			375	$ -		375	$ -	$ -	
			375	$ -		375	$ -	$ -	
			375	$ -		375	$ -	$ -	
			375	$ -		375	$ -	$ -	
			375	$ -		375	$ -	$ -	
Sub-Total A				$ 26.90			$ 15.10	**-$ 11.80**	**-43.86%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0012	375	-$ 0.45	$ 0.0029	375	$ 1.09	$ 1.54	-341.67%
			375	$ -		375	$ -	$ -	
			375	$ -		375	$ -	$ -	
			375	$ -		375	$ -	$ -	
Low Voltage Service Charge		$ 0.0011	375	$ 0.41	$ 0.0015	375	$ 0.56	$ 0.15	36.36%
Smart Meter Entity Charge						375	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.86**			**$ 16.75**	**-$ 10.11**	**-37.64%**
RTSR - Network	per kWh	$ 0.0048	405	$ 1.94	$ 0.0055	401	$ 2.21	$ 0.27	13.65%
RTSR - Line and Transformation Connection	per kWh	$ 0.0017	405	$ 0.69	$ 0.0019	401	$ 0.76	$ 0.07	10.85%
Sub-Total C - Delivery (including Sub-Total B)				**$ 29.49**			**$ 19.72**	**-$ 9.77**	**-33.13%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	405	$ 2.10	$ 0.0052	401	$ 2.09	-$ 0.02	-0.82%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	405	$ 0.45	$ 0.0011	401	$ 0.44	-$ 0.00	-0.82%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	405	$ 0.28	$ 0.0007	401	$ 0.28	-$ 0.00	-0.82%
Energy - RPP - Tier 1	per kWh	$ 0.0750	405	$ 30.34	$ 0.0750	401	$ 30.09	-$ 0.25	-0.82%
Energy - RPP - Tier 2	per kWh	$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0650	259	$ 16.83	$ 0.0650	257	$ 16.69	-$ 0.14	-0.82%
TOU - Mid Peak	per kWh	$ 0.1000	73	$ 7.28	$ 0.1000	72	$ 7.22	-$ 0.06	-0.82%
TOU - On Peak	per kWh	$ 0.1170	73	$ 8.52	$ 0.1170	72	$ 8.45	-$ 0.07	-0.82%
Total Bill on RPP (before Taxes)				**$ 62.92**			**$ 52.87**	**-$ 10.04**	**-15.96%**
HST		13%		$ 8.18	13%		$ 6.87	-$ 1.31	-15.96%
Total Bill (including HST)				$ 71.09			$ 59.75	-$ 11.35	-15.96%
Ontario Clean Energy Benefit [1]				-$ 7.11			-$ 5.97	$ 1.14	-16.03%
Total Bill on RPP (including OCEB)				**$ 63.98**			**$ 53.78**	**-$ 10.21**	**-15.95%**
Total Bill on TOU (before Taxes)				**$ 65.20**			**$ 55.15**	**-$ 10.06**	**-15.43%**
HST		13%		$ 8.48	13%		$ 7.17	-$ 1.31	-15.43%
Total Bill (including HST)				$ 73.68			$ 62.31	-$ 11.37	-15.43%
Ontario Clean Energy Benefit [1]				-$ 7.37			-$ 6.23	$ 1.14	-15.47%
Total Bill on TOU (including OCEB)				**$ 66.31**			**$ 56.08**	**-$ 10.23**	**-15.42%**

Loss Factor (%) 7.88% 7.00%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB2012-0176
Exhibit:	8
Tab:	4
Schedule:	3
Appendix:	2
Page:	5
Date:	9-Oct-12

Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

Consumption 200 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

0.20 KW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 2.5300	1	$ 2.53	$ 4.5800	1	$ 4.58	$ 2.05	81.03%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
SMDR	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 13.0802	0.2	$ 2.62	$ 23.6800	0.2	$ 4.74	$ 2.12	81.04%
Smart Meter Disposition Rider			0.2	$ -		0.2	$ -	$ -	
LRAM & SSM Rate Rider	per kW		0.2	$ -		0.2	$ -	$ -	
Rate Rider for Tax Adjustments	per kW	-$ 0.2288	0.2	-$ 0.05		0.2	$ -	$ 0.05	-100.00%
	per kWh		0.2	$ -		0.2	$ -	$ -	
			0.2	$ -		0.2	$ -	$ -	
			0.2	$ -		0.2	$ -	$ -	
			0.2	$ -		0.2	$ -	$ -	
			0.2	$ -		0.2	$ -	$ -	
			0.2	$ -		0.2	$ -	$ -	
Sub-Total A				$ 5.10			$ 9.32	**$ 4.22**	**82.66%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.1627	0.2	-$ 0.23	$ 3.2891	0.2	$ 0.66	$ 0.89	-382.88%
Global Adjustment Rate Rider	per kW		0.2	$ -		0.2	$ -	$ -	
			0.2	$ -		0.2	$ -	$ -	
			0.2	$ -		0.2	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.3153	0.2	$ 0.06	$ 0.4397	0.2	$ 0.09	$ 0.02	39.45%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4.93**			**$ 10.06**	**$ 5.13**	**104.06%**
RTSR - Network	per kW	$ 1.5096	0	$ 0.30	$ 1.7234	0.2	$ 0.34	$ 0.04	14.16%
RTSR - Line and Transformation Connection	per kW	$ 0.5476	0	$ 0.11	$ 0.5890	0.2	$ 0.12	$ 0.01	7.56%
Sub-Total C - Delivery (including Sub-Total B)				**$ 5.34**			**$ 10.52**	**$ 5.18**	**97.00%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	200	$ 1.04	$ 0.0052	200	$ 1.04	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	200	$ 0.22	$ 0.0011	200	$ 0.22	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	200	$ 0.14	$ 0.0007	200	$ 0.14	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	216	$ 16.18	$ 0.0750	215.76	$ 16.18	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0650	138	$ 8.98	$ 0.0650	138.086	$ 8.98	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1000	39	$ 3.88	$ 0.1000	38.8368	$ 3.88	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1170	39	$ 4.54	$ 0.1170	38.8368	$ 4.54	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 23.17**			**$ 28.36**	**$ 5.18**	**22.36%**
HST		13%		$ 3.01	13%		$ 3.69	$ 0.67	22.36%
Total Bill (including HST)				$ 26.19			$ 32.04	$ 5.86	22.36%
Ontario Clean Energy Benefit [1]				-$ 2.62			-$ 3.20	-$ 0.58	22.14%
Total Bill on RPP (including OCEB)				**$ 23.57**			**$ 28.84**	**$ 5.28**	**22.39%**
Total Bill on TOU (before Taxes)				**$ 24.40**			**$ 29.58**	**$ 5.18**	**21.24%**
HST		13%		$ 3.17	13%		$ 3.85	$ 0.67	21.24%
Total Bill (including HST)				$ 27.57			$ 33.42	$ 5.86	21.24%
Ontario Clean Energy Benefit [1]				-$ 2.76			-$ 3.34	-$ 0.58	21.01%
Total Bill on TOU (including OCEB)				**$ 24.81**			**$ 30.08**	**$ 5.28**	**21.27%**

Loss Factor (%) 7.88% 7.00%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB2012-0176
Exhibit:	8
Tab:	4
Schedule:	3
Appendix:	2
Page:	6
Date:	9-Oct-12

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 500 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

3.00 **KW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 3.8800	1	$ 3.88	$ 4.3100	1	$ 4.31	$ 0.43	11.08%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
SMDR	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.2599	3	$ 9.78	$ 3.6356	3	$ 10.91	$ 1.13	11.52%
Smart Meter Disposition Rider			3	$ -		3	$ -	$ -	
LRAM & SSM Rate Rider	per kW		3	$ -		3	$ -	$ -	
Rate Rider for Tax Adjustments	per kW	-$ 0.2780	3	-$ 0.83		3	$ -	$ 0.83	-100.00%
	per kWh		3	$ -		3	$ -	$ -	
			3	$ -		3	$ -	$ -	
			3	$ -		3	$ -	$ -	
			3	$ -		3	$ -	$ -	
			3	$ -		3	$ -	$ -	
			3	$ -		3	$ -	$ -	
Sub-Total A				$ 12.83			$ 15.22	**$ 2.39**	**18.64%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0847	3	$ 0.25	$ 1.5929	3	$ 4.78	$ 4.52	1780.42%
Global Adjustment Rate Rider	per kW		3	$ -		3	$ -	$ -	
			3	$ -		3	$ -	$ -	
			3	$ -		3	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.3079	3	$ 0.92	$ 0.4502	3	$ 1.35	$ 0.43	46.22%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 14.00**			**$ 21.35**	**$ 7.34**	**52.43%**
RTSR - Network	per kW	$ 1.4976	3	$ 4.49	$ 1.7372	3	$ 5.21	$ 0.72	16.00%
RTSR - Line and Transformation Connection	per kW	$ 0.5348	3	$ 1.60	$ 0.6031	3	$ 1.81	$ 0.20	12.77%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.10**			**$ 28.37**	**$ 8.27**	**41.12%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	500	$ 2.60	$ 0.0052	500	$ 2.60	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	500	$ 0.55	$ 0.0011	500	$ 0.55	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	500	$ 0.35	$ 0.0007	500	$ 0.35	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	539	$ 40.46	$ 0.0750	539.4	$ 40.46	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0650	345	$ 22.44	$ 0.0650	345.216	$ 22.44	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1000	97	$ 9.71	$ 0.1000	97.092	$ 9.71	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1170	97	$ 11.36	$ 0.1170	97.092	$ 11.36	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 64.31**			**$ 72.57**	**$ 8.27**	**12.85%**
HST		13%		$ 8.36	13%		$ 9.43	$ 1.07	12.85%
Total Bill (including HST)				$ 72.67			$ 82.01	$ 9.34	12.85%
Ontario Clean Energy Benefit [1]				-$ 7.27			-$ 8.20	-$ 0.93	12.79%
Total Bill on RPP (including OCEB)				**$ 65.40**			**$ 73.81**	**$ 8.41**	**12.86%**
Total Bill on TOU (before Taxes)				**$ 67.36**			**$ 75.63**	**$ 8.27**	**12.27%**
HST		13%		$ 8.76	13%		$ 9.83	$ 1.07	12.27%
Total Bill (including HST)				$ 76.12			$ 85.46	$ 9.34	12.27%
Ontario Clean Energy Benefit [1]				-$ 7.61			-$ 8.55	-$ 0.94	12.35%
Total Bill on TOU (including OCEB)				**$ 68.51**			**$ 76.91**	**$ 8.40**	**12.26%**

Loss Factor (%) 7.88% 7.00%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Exhibit 9:

DEFERRAL AND VARIANCE ACCOUNTS

Exhibit 9: Deferral And Variance Accounts

Tab 1 (of 4): Status of Deferral and Variance Accounts

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

WPI follows and is in compliance with the OEB's Uniform System of Accounts for electricity distributors. All accounts are used in accordance with the Accounting Procedures Handbook.

WPI used the cash method to calculate carrying charges up to June 30, 2012. Effective July 1, 2012 WPI has transitioned to the accrual method in accordance with the Board's directive. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

At December 31, 2011, WPI has balances in the following Board-approved deferral and variance accounts:

Description of Group 1 and Group 2 Accounts

Group 1 Accounts

• **1550 – Retail Settlement Variance Account – Low Voltage Variance Account**

Account Description: On a monthly basis, this account is used to record the net of: i) the amount charged by a host distributor to an embedded distributor for transmission or low voltage services (Account 4750); and ii) the amount billed to the embedded distributor's customers based on the embedded distributor's approved LV rate(s) (Account 4075).

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for account 1550. The December 31, 2011 audited balance of $195,725 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $229,275.

.• 1580 – Retail Settlement Variance Account [1] – Wholesale Market Service Charges ("RSVA$_{WMS}$")

Account Description: The Retail Settlement Variance Account is used to record net differences in Wholesale Market Service Charges, including accruals.

RSVA$_{WMS}$ is used to record the difference between the amount of wholesale market services charges paid to the IESO or host distributor and the amounts billed to customers for wholesale market services charges. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for account 1580. The December 31, 2011 audited balance of $866,594 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $325,379.

• 1584 – Retail Settlement Variance Account – Retail Transmission Network Charges ("RSVA$_{NW}$")

Account Description: The Retail Settlement Variance Account is used to record net differences in Retail Transmission Network Charges, including accruals.

RSVA$_{NW}$ is used to record the difference between the amount of retail transmission network charges paid to the IESO or host distributor and the amounts billed to customers for retail transmission network costs. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April

30, 2013 for account 1584. The December 31, 2011 audited balance of $73,201 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $37,079.

- **1586 – Retail Settlement Variance Account – Retail Transmission Connection Charges ("RSVA$_{CN}$")**

Account Description: The Retail Settlement Variance Account is used to record net differences in Retail Transmission Connection Charges, including accruals.

RSVA$_{CN}$ is used to record the difference between the amount of retail transmission connection costs paid to the IESO or host distributor and the amounts billed to customers for retail transmission connection costs. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for account 1586. The December 31, 2011 audited balance of $805,576 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $965,290.

- **1588 – Retail Settlement Variance Account– Power ("RSVA$_{POWER}$")**

Account Description: The Retail Settlement Variance Account is used to record net differences between the energy amount charged to customers, including accruals AND the energy charge to a distributor using the settlement invoice received from the IESO, host distributor or embedded generator

The $RSVA_{POWER}$ account is to be used to record the net differences in energy costs using the settlement invoice received from the IESO, host distributor, or embedded generator and the amounts billed to customers for energy. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account.

The RSVA power account is designed to capture variances due to billing timing differences (i.e. electricity charged by IESO to LDCs vs. electricity billed by LDCs to their customers), price and quantity differences (i.e. arising from final vs. preliminary IESO settlement invoices), and line loss differences (i.e. actual vs. estimated line loss factors).

This account is not designed to capture any price differences between the regulated price plan (RPP) and spot prices applicable to RPP customers. This is the function of the Ontario Power Authority (OPA) RPP variance account which is trued-up in accordance with the terms established by the Board for the RPP.

Accordingly, since the RSVA power account is generic to all customers of an LDC, disposition of the account balance in rates is attributable to all its customers.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for account 1588 RSVA. The December 31, 2011 audited balance of $1,386,005 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $1,335,010.

- **1588 – Retail Settlement Variance Account – Global Adjustment (“$RSVA_{GA}$”)**

Account Description: The Retail Settlement Variance Account is used to record the Global Adjustment net differences between the global adjustment amount billed to non-RPP customers, including accruals AND the global adjustment charge to a distributor *using the settlement invoice received from the IESO, host distributor or embedded generator.*

The $RSVA_{GA}$ account is used to record the net differences between the global adjustment amount billed, to non-RPP consumers and the global adjustment charge to a distributor for non-RPP consumers, using the settlement invoice received from the IESO, host distributor or embedded generator. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account.

The 1588 RSVA power - Sub-account Global Adjustments is designed for the global adjustments applicable to non-RPP customers. Hence, the disposition of the account balance should be attributable to non-RPP customers.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for account 1588_{GA}. The December 31, 2011 audited balance of $538,732 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $600,512.

- **1595 – Recovery/Disposition of Regulatory Asset Balances (Recovery or Refund Period completed)**

Account Description: This account is used to record the disposition and recoveries of deferral and variance account balances for electricity distributors receiving approval to recover (or refund) account balances in rates as part of the regulatory process. The Sub-account "Disposition of Account Balances Approved in 2010" captures amounts approved for recovery (or refund) through the 2010 rate review process.

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery.

Sub-Account 2009 for EB-2009-0236: In accordance with the OEB EB-2009-0326 Decision and Order for WPI's 2010 IRM, the December 31, 2008 debit balance of $172,723 including interest forecast to April 30, 2010 was transferred to a subaccount of 1595 in May 2010. WPI was further ordered to record the shared tax savings resulting from the Ontario Capital Tax rate decrease for 2010. The debit balance of $172,723 was recorded in the sub-account of 1595 for disposition at a future rate proceeding. As of April 30, 2011, the disposition period for this account was completed.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for Sub-Account 2009. The December 31, 2011 audited balance of $2,252 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $2,252.

Sub-Account 2010 for EB-2010-0122: In accordance with the OEB EB-2010-0122 Decision and Order for WPI's 2011 IRM, the December 31, 2009 debit balance of $1,212,182 including interest forecast to April 30, 2011 was transferred to a subaccount of 1595 in May 2011. WPI was further ordered to record the shared tax savings resulting from the Ontario Capital Tax rate decrease for 2011. The debit balance of $1,212,182 was recorded in the sub-account of 1595 for disposition at a future rate proceeding. As of April 30, 2012, the disposition period for this account was completed.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for Sub-Account 2010. The December 31, 2011 audited balance of $38,198 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $38,747.

Sub-Account 2011 for EB-2011-0205: In accordance with the OEB EB-2011-0205 Decision and Order for WPI's 2012 IRM, the December 31, 2010 debit balance of $540,494, excluding the global adjustment sub-account, but including interest forecast to April 30, 2012 was transferred to a sub-account of 1595 in May 2012. WPI was further ordered to record the shared tax savings resulting from the Ontario Capital Tax rate decrease for 2012. The debit balance of $540,494 was recorded in the subaccount of 1595 for disposition at a future rate proceeding. WPI is not requesting disposition of the residual balance in this subaccount, as the balance has not been audited.

Group 2 Accounts

• 1508 – Other Regulatory Assets – Deferred IFRS Transition Sub-Account

Account Description: Amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board.

This account includes amounts paid for one-time incremental International Financial Reporting Standards (IFRS) transition costs not included in rates, until the transition to IFRS has commenced. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

WPI has established Account 1508 – sub account – Deferred IFRS Transition Costs in accordance with the Board requirements. The Board permits the deferral of one-time administrative costs caused by the transition of accounting policies, procedures, systems, and processes to International Financial Reporting Standards ("IFRS") in this sub-account. The Board also permits interest carrying charges to be calculated on the monthly opening principal balance of this sub-account at the Board's prescribed interest rates. Based on this guidance, WPI is deferring professional accounting fees, incremental salaries, wages, and benefits of staff attributable to the transition to IFRS, staff training costs solely related to IFRS and carrying charges solely related to these items.

In accordance with the Minimum Filing Requirements[1] WPI is seeking disposition of the December 31, 2011 audited balance of for one-time administrative costs in this Application which includes carrying charges of $38,814 up to April 30, 2013.

Appendix 2-U - One-Time Incremental IFRS Transition Costs is presented at Exhibit 9, Tab 1, Schedule 1, Attachment 1.

The majority of the incremental IFRS transition costs relate to third party consultants that were used to help implement IFRS. This includes consultancy costs from KPMG to assist with IFRS implementation within WPI. KPMG was hired to assist with the transitional analysis, analysis regarding fixed assets componentization, useful lives, and overheads. This work was completed with the assistance of WPI staff and in consultation with external auditors by the end of December 31, 2011. These costs would not be incurred if WPI was not required to transition to IFRS.

The remaining costs included in this account relate to other resources that were used to assist in preparing the documentation of our new policies, procedures and process flows as a result of implementing IFRS. There were also costs included in this account for training. These costs would not have been incurred if WPI had not been required to transition to IFRS.

WPI confirms these costs are not already approved and included for recovery in distribution rates. WPI also confirms the balance requested for disposition does not include capital costs, ongoing IFRS compliance costs, impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income, costs related to system upgrades where IFRS was not the major reason for conversion, and costs that are capital in nature.

[1] Section 2.12.3 of Chapter 2-Filing Requirements For Electricity Transmission and Distribution Applications, issued June 28, 2012

WPI is in a position to implement IFRS on January 1, 2013, pending future decisions and direction from the IASB, the AcSB, and the OEB. Until then, WPI will continue to incur costs associated with the transition to IFRS. WPI therefore requests the continuation of the 1508 – Other Regulatory Assets – Sub Account – Deferred IFRS Transition Costs for disposition in a future rate proceeding. WPI has incurred additional professional accounting fees, consulting fees and training expenditures in 2012. Consequently, WPI is requesting disposition of the 2011 balance only and respectfully requests continuation of the IFRS Transition Cost sub-account 1508 for disposition in a future rate proceeding.

- **1508 – Other Regulatory Assets – Incremental Capital Charges**

This account includes amounts charged by Hydro One based on settlement invoices for Incremental Capital charges. WPI has established account 1508 – sub account Incremental Capital Charges in accordance with the Board requirements. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, plus forecasted interest through April 30, 2013. The requested amount is a debit balance of $17,661.

- **1518 – Retail Cost Variance Account - Retail**

This account includes the amount of net revenues derived from the services related to establishing Service Agreements, Distributor-Consolidated Billing, Retailer-Consolidated Billing and Split Billing, as well as the costs of entering into Service Agreements and related to contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the incremental costs incurred to provide the services above.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. For 2013, WPI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a credit balance of $82,171.

- **1531 - Renewal Energy Enabling Deferral**

On September 9, 2009, the *Green Energy and Green Economy Act, 2009* ("GEA") was enacted. The GEA amended a number of Acts and regulations including the *Ontario Energy Board Act, 1998* (the "OEB Act") and the *Electricity Act 1998* ("Electricity Act") to enable distributors to do renewable generation connections and smart grid development.

Exhibit 2, Tab 7 contains more information regarding WPI's GEA Plan, actual and planned spending, calculation of direct benefits attributable to WPI's customers and the portion to be provincially funded; it should be read in conjunction with this section.

The OEB authorized several deferral accounts to record GEA related spending, as these costs were not incorporated in the distribution rates of LDCs.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, plus forecasted interest through April 30, 2013. The requested amount is a debit balance of $679.

- **1548 – Retail Cost Variance Account – STR (Service Transaction Request)**

This account includes the amount of net revenues derived from the service transaction requests related to request fees, processing fee, information request fees, default fees and other associated costs fees as well as the incremental cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated with the above items.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. For 2013, WPI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a debit balance of $129,942.

- **1562 – Deferred Payments in Lieu of Taxes**

This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2006. The total claim amount of $187,624 noted in the EDDVAR Continuity Schedule represents the unadjusted account balance prior to receiving the Decision and Order of April 19, 2012. WPI will be updating our RRR Filing effective June 30, 2012 to reflect the amounts outlined in the Decision and Order.

In accordance with the Decision and Order dated April 19, 2012, WPI was ordered to transfer the balance of Account 1562 to the principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements of Article 220, Account Descriptions, of the Accounting Procedures Handbook for the Electricity Distributors. WPI has transferred a debit balance of $33,814 which includes principal of $37,386 and an interest credit balance of $3,572 to Account 1595 for disposition to customers from May 1, 2012 to April 30, 2013.

- **1563 – Contra Account - Deferred PILS**

Amounts recorded in this account are applicable to a distributor using the third accounting method approved for recording entries in account #1562 in accordance with the Board's accounting instructions for PILs as set out in the April 2003 Frequently Asked Questions on the Accounting Procedures Handbook. The offsetting entry of each entry in account 1562 shall be made to this contra account.

- **1582 – Retail Settlement Variance Account – Retail One Time Charges ("RSVA$_{ONE-TIME}$")**

Account Description: The Retail Settlement Variance Account is used to record net differences in Wholesale Market Service Charges (not normally already incorporated in Wholesale Market Service Rate), including accruals.

$RSVA_{ONE-TIME}$ is used to record the difference between the amount of wholesale market services charges paid to the IESO or host distributor and the amounts billed to customers for wholesale market services charges. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account.

For 2013, WPI is requesting disposition of the December 31, 2011 audited balance, less the 2012 IRM approved disposition amounts plus the forecasted interest through April 30, 2013 for account 1586. The December 31, 2011 audited balance of $8,776 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $8,767.

The applicant intends to continue all accounts identified above on an ongoing basis that are listed in Group 1. In the Group 2 accounts, WPI intends to continue with 1508, 1518, 1531, and 1548.

The 2013_EDDVAR_Continuity_Schedule_CoS_v2_20120706 detailing each account is being filed in conjunction with this application.

All other deferral and variance accounts in Group 2 are not sought for disposition as they require a prudence review and lend themselves to a disposition threshold[2]

Table 1 below provides the interest rates by quarter that are applied to calculate actual and forecast carrying charges for each regulatory and variance account.

Table 1: Interest Rates Applied to Deferral and Variance Accounts (%)

[2] Page 5 of Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)

	Approved Deferral and Variance Accounts
Quarter by Year	Prescribed Interest Rate
Q2 2012	1.47
Q1 2012	1.47
Q4 2011	1.47
Q3 2011	1.47
Q2 2011	1.47
Q1 2011	1.47
Q4 2010	1.20
Q3 2010	0.89
Q2 2010	0.55
Q1 2010	0.55
Q4 2009	0.55
Q3 2009	0.55
Q2 2009	1.00
Q1 2009	2.45
Q4 2008	3.35
Q3 2008	3.35
Q2 2008	4.08
Q1 2008	5.14
Q4 2007	5.14
Q3 2007	4.59
Q2 2007	4.59
Q1 2007	4.59
Q4 2006	4.59
Q3 2006	4.59
Q2 2006	4.14
Q1 2006	7.25
Q4 2005	7.25
Q3 2005	7.25
Q2 2005	7.25
Q1 2005	7.25

The applicant is not requesting any new accounts or sub-accounts at this time. The applicant will continue to monitor OEB directives and implement new accounts as set out by the OEB and identified in the Accounting Procedures Handbook or other sources of information as required to comply with regulation.

The applicant has not made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in both cost of service and IRM proceedings.

The filing requirements 2.12 Exhibit 9 states that a breakdown of energy sales and cost of power expenses, as reported in the 2011 audited financial statements is requested.

Please refer to Table 2 below for an excerpt from the model that WPI used to calculate its projected rates.

Table 2: Energy Sales and Cost of Power Expenses

	2011 Actual	2010 Actual	2009 Actual	2009 Approved
4006-Residential Energy Sales	- 18,686,705	- 16,469,476	- 9,725,926	- 12,946,973
4010-Commercial Energy Sales	- 3,928,726	- 3,924,559	- 3,228,202	- 10,558,871
4025-Street Lighting Energy Sales	- 77,345	- 91,677	- 237,301	- 271,488
4030-Sentinel Lighting Energy Sales	- 1,273	- 1,209	- 1,121	- 1,090
4035-General Energy Sales	- 4,260,506	- 4,192,160	- 5,329,650	- 4,649,407
4055-Energy Sales for Resale	- 3,353,276	- 4,945,375	- 4,225,930	
	- 30,307,831	- 29,624,456	- 22,748,130	- 28,427,829
4705-Power Purchased	30,307,831	29,624,456	22,748,130	28,427,829
Net	-	-	-	-

As can be seen above, there is no difference between energy sales and cost of power expense reported numbers.

File Number:	EB2012-0176
Exhibit:	9
Tab:	1
Schedule:	1
Attachment:	1
Page:	1
Date:	Ocotber 9, 2012

Appendix 2-U
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Carrying Charges to Dec 31, 2011	Total Audited Actual Costs to Dec 31, 2011	RRR 2.1.7 Balance 31-Dec-11	Variance [2]	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 4,000	$ 7,500	$ 16,500		$ 28,000			Auditor Consulting Fees
professional legal fees					$ -			
salaries, wages and benefits of staff added to support the transition to IFRS					$ -			
associated staff training and development costs	$ 2,714	$ 1,285	$ 1,129		$ 5,128			
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion		$ 4,157	$ 293		$ 4,450			
Carrying Charges				$ 498	$ 498			
					$ -			
					$ -			
					$ -			
					$ -			
					$ -			
					$ -			
Insert description of additional item(s) and new rows if needed.					$ -			
Total	$ 6,714	$ 12,942	$ 17,922	$ 498	$ 38,076		$ 38,076	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 Applicants are to provide an explanation of material variances in evidence

Tab 2 (of 4): Clearance of Deferral and Variance Accounts

SELECTION OF BALANCES FOR DISPOSITION

Attachment 1 contains account balances from the 2011 Audited Financial Statements as at December 31, 2011. There are some variances, which are explained in Table 1 below, for account 1590, 1508, 1531, 1562, 1521, 1563 and 1595. The remaining accounts agree to the 2011 year end balances for RRR filing 2.1.7 Trial Balance as filed April 30, 2012 with the OEB.

Table 1: Variance between RRR and 2011 Account Balance

Account Descriptions	Account Number	Variance RRR vs. 2011 Balance	Explanation
Group 1 Accounts			
Recovery of Regulatory Asset Balances	1590	$ (15,715.00)	In the Board's Decision and Order dated April 19, 2012 (EB-2011-0205); the Board approved an amount of interest on Account 1590 that had not been previously recorded in Account 1590
Group 2 Accounts			
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ (9,106.00)	Costs associated with retail and IESO related settlement issues have been erroneously allocated to this account. Amounts have been reallocated to Account 4705 - Power Purchased in 2012.
Renewable Generation Connection Capital Deferral Acc	1531	$ 8,315.00	Costs associated with the purchase of bi-directional meters had been erroneously allocated to this account. Amounts were reallocated to account 1860 - Meters in 2012.
Deferred Payments in Lieu of Taxes	1562	$ 153,810.00	In the Board's Decision and Order dated May 1, 2012 (EB-2011-0205); the Board approved an amount of PILs recovery in the amount of $33,814. This account has been adjusted to reflect the Board approved amount.
Special Purpose Charge Assessment Variance Account	1521	$ 7.00	In the Board's Decision and Order dated April 19, 2012 (EB-2011-0205); the Board approved an addional amount of interest to April 30, 2012 that had not been included in the December 31, 2011 balance.
Deferred PILs Contra Account [5]	1563	$ (97,999.00)	In the Board's Decision and Order dated May 1, 2012 (EB-2011-0205); the Board approved an amount of PILs recovery in the amount of $33,814. This account has been adjusted to reflect the Board approved amount.
Disposition and Recovery of Regulatory Balances[7]	1595	$ (11,467.00)	As the the Board issued FAQ's dated July 2012; WPI reallocated variance costs related to the Late Payment Penalty charge and the Tax Sharing Rate Rider

Account Descriptions	Account Number	2012: Principal Disposition during 2012 - instructed by Board	2012: Interest Disposition during 2012 - instructed by Board	2012: Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	2012: Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest on Dec-31-11 Balances: Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR: As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550	-$ 25,820	-$ 3,745	$ 218,074	$ 7,216	$ 2,916	$ 1,069	$ 229,275	$ 195,725	$ -
RSVA - Wholesale Market Service Charge	1580	-$ 485,647	-$ 51,488	-$ 373,961	$ 44,502	$ 5,912	-$ 1,832	-$ 325,379	-$ 866,594	$ -
RSVA - Retail Transmission Network Charge	1584	-$ 99,892	-$ 11,673	$ 29,287	$ 9,077	-$ 1,428	$ 144	$ 37,079	-$ 73,201	$ -
RSVA - Retail Transmission Connection Charge	1586	-$ 134,666	$ 4,256	$ 897,923	$ 38,063	$ 24,904	$ 4,400	$ 965,290	$ 805,576	$ -
RSVA - Power (excluding Global Adjustment)	1588	$ 70,829	$ 30,268	$ 1,231,898	$ 53,010	$ 44,066	$ 6,036	$ 1,335,010	$ 1,386,005	$ -
RSVA - Power - Sub-account - Global Adjustment	1588	-$ 39,916	-$ 17,285	$ 600,993	-$ 5,060	$ 1,634	$ 2,945	$ 600,512	$ 538,732	$ -
Recovery of Regulatory Asset Balances	1590		$ 15,715	$ -	$ -		$ -	$ -	$ -	-$ 15,715
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$ -	$ -			$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$ -	$ 2,252			$ 2,252	$ 2,252	$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			-$ 37,434	-$ 764	-$ 549		-$ 38,747	-$ 38,198	-$ 0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 715,112	-$ 33,952	$ 2,566,780	$ 148,296	$ 77,454	$ 12,761	$ 2,805,291	$ 1,950,297	-$ 15,715
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 675,196	-$ 16,667	$ 1,965,787	$ 153,356	$ 75,820	$ 9,816	$ 2,204,779	$ 1,411,565	-$ 15,715
RSVA - Power - Sub-account - Global Adjustment	**1588**	-$ 39,916	-$ 17,285	$ 600,993	-$ 5,060	$ 1,634	$ 2,945	$ 600,512	$ 538,732	$ -
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$ 37,578	$ 499	$ 552	$ 184	$ 38,814	$ 38,077	$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$ 16,943	$ 386	$ 249	$ 83	$ 17,661	$ 17,329	$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508			$ -	$ -			$ -	-$ 9,106	-$ 9,106
Retail Cost Variance Account - Retail	1518			-$ 80,068	-$ 2,103	-$ 1,177	-$ 392	-$ 83,740	-$ 82,171	$ -
Misc. Deferred Debits	1525			$ -	$ -			$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531			$ -	$ -		$ -	$ -	$ 8,315	$ 8,315
Renewable Generation Connection OM&A Deferral Account	1532			$ 653	$ 13	$ 10	$ 3	$ 679	$ 666	$ -
Renewable Generation Connection Funding Adder Deferral Account	1533			$ -	$ -			$ -		$ -
Smart Grid Capital Deferral Account	1534			$ -	$ -			$ -		$ -
Smart Grid OM&A Deferral Account	1535			$ -	$ -			$ -		$ -
Smart Grid Funding Adder Deferral Account	1536			$ -	$ -			$ -		$ -
Retail Cost Variance Account - STR	1548			$ 124,932	$ 2,561	$ 1,837	$ 612	$ 129,942	$ 127,493	$ -
Board-Approved CDM Variance Account	1567			$ -	$ -			$ -		$ -
Extra-Ordinary Event Costs	1572			$ -	$ -			$ -		$ -
Deferred Rate Impact Amounts	1574			$ -	$ -			$ -		$ -
RSVA - One-time	1582			$ 29	-$ 8,805	$ 8	$ 0	-$ 8,767	-$ 8,776	$ -
Other Deferred Credits	2425			$ -	$ -			$ -		$ -
Group 2 Sub-Total		$ -	$ -	$ 100,067	-$ 7,449	$ 1,479	$ 490	$ 94,587	$ 91,827	-$ 791
Deferred Payments in Lieu of Taxes	1562	$ 37,386	-$ 3,572	$ -	$ -			$ -	$ 187,624	$ 153,810
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$ -	$ -			$ -		$ -
										$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 677,726	-$ 37,524	$ 2,666,847	$ 140,847	$ 78,933	$ 13,251	$ 2,899,878	$ 2,229,748	$ 137,304

Account Descriptions	Account Number	2012 Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ 766	$ 874	$ -	$ -			$ -	$ 1,647	$ 7
										$ -
LRAM Variance Account	**1568**		$ -	$ -	$ -			$ -		$ -
Total including Account 1521 and Account 1568		-$ 676,960	-$ 36,650	$ 2,666,847	$ 140,847	$ 78,933	$ 13,251	$ 2,899,878	$ 2,231,395	$ 137,311
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555			$ 3,154,328	$ 65,307	$ 46,415	$ 15,682	$ 3,281,732	$ 3,219,635	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555			-$ 930,513	-$ 30,424	-$ 13,510	-$ 4,560	-$ 979,007	-$ 960,937	$ 0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555			$ 705,375	$ -			$ 705,375	$ 705,375	$ -
Smart Meter OM&A Variance[11]	1556			$ 743,115	$ 11,327	$ 10,689	$ 3,641	$ 768,772	$ 754,442	$ -
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563	-$ 37,386	$ 3,572	$ -	$ -			$ -	-$ 131,813	-$ 97,999
IFRS-CGAAP Transition PP&E Amounts[10]	1575			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$ -	$ -			$ -		$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ 676,960	$ 36,650	-$ 676,960	$ 489,251			-$ 187,709	$ 514,434	-$ 11,467

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ol

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refu
balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pr
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall b

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

CALCULATION OF RATE RIDERS

Westario Power Inc. is requesting disposition of the variance accounts according to the Report of the Board EB-2009-0046 which states that “at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline.”

WPI is seeking a disposition period over two years so as to ensure that the rate impact to ratepayers will not be unduly high compared to current bills. A complete analysis of the rate riders is found in Exhibit 8 of this application. The amounts are comprised of the audited balances as of December 31, 2011 and the forecasted interest through to April 30, 2013.

Attachment 1 shows the billing determinants as set out in the EDVARR model issued by the board. The amounts for disposition have been allocated to individual customer classes and are based on 2011 Actual data as filed in the applicant’s 2011 RRR Filing of April 30, 2012.

Attachment 2 indicates the Allocators for each of the disposition amounts. The allocators are based on 2011 Actual data as filed in the applicant’s 2011 RRR Filing of April 30, 2012.

Finally Attachment 3 presents the rate rider calculation for the deferral and variance account balances for which WPI is seeking disposition. The first schedule excludes Global Adjustment and the next schedule is for the Global Adjustment.

Westario Power Inc.
EB-2012-0176
Filed: October 9. 2012
Exhibit 9
Tab 2
Schedule 2
Attachment 1

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the most recent 12-month actual volumetric data, use the most recent 12-month actual data. Do not enter data for the MicroFit class.

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]	1568 LRAM Variance Account Class Allocation ($ amounts)
Residential	kWh	18,875	200,817,509		17,769,775	-				75.50%	75.50%	
General Service <50 kW	kWh	2,365	63,827,597		12,462,639	-				12.90%	12.90%	
General Service 50 to 4,999 kW	kW	252	168,041,245	466,442	145,315,171	403,360				11.40%	11.40%	
Unmetered Scattered Load	kWh	69	283,437		54,183	-				0.10%	0.10%	
Sentinel Lighting	kW	6	18,155	17		-				0.00%	0.00%	
Street Lighting	kW	6,077	5,431,816	15,101	5,162,433	14,352				0.00%	0.00%	
						-						
						-						
						-						
						-						
						-						
						-						
						-						
						-						
						-						
						-						
						-						
						-						
						-						
						-						
Total		**27,644**	**438,419,759**	**481,560**	**180,764,201**	**417,712**	**$ -**	**0%**	**0%**	**100%**	**100%**	**$ -**
												$ -
											Variance	$ -
											1185009	

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balances

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

Deferral/Variance Account Workform for 2013 Filers

		Amounts from Sheet 2	Allocator	Residential	General Service <50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
LV Variance Account	1550	229,275	kWh	105,019	33,379	87,878	148	9	2,841
RSVA - Wholesale Market Service Charge	1580	(325,379)	kWh	(149,039)	(47,371)	(124,714)	(210)	(13)	(4,031)
RSVA - Retail Transmission Network Charge	1584	37,079	kWh	16,984	5,398	14,212	24	2	459
RSVA - Retail Transmission Connection Charge	1586	965,290	kWh	442,149	140,532	369,984	624	40	11,959
RSVA - Power (excluding Global Adjustment)	1588	1,335,010	kWh	611,499	194,358	511,694	863	55	16,540
RSVA - Power - Sub-account - Global Adjustment	1588	600,512	Non-RPP kWh	59,032	41,402	482,748	180	0	17,150
Recovery of Regulatory Asset Balances	1590	0	kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0	kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	2,252	kWh	1,032	328	863	1	0	28
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(38,747)	kWh	(17,748)	(5,641)	(14,851)	(25)	(2)	(480)
Total of Group 1 Accounts (excluding 1588 sub-account)		**2,204,779**		**1,009,896**	**320,984**	**845,066**	**1,425**	**91**	**27,316**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	38,814		26,501	3,321	354	97	8	8,532
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	17,661		12,059	1,511	161	44	4	3,882
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0		0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(83,740)		(57,177)	(7,164)	(763)	(209)	(18)	(18,409)
Misc. Deferred Debits	1525	0		0	0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0	0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	679		463	58	6	2	0	149
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0	0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0	0	0	0
Smart Grid OM&A Deferral Account	1535	0		0	0	0	0	0	0
Smart Grid Funding Adder Deferral Account	1536	0		0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	129,942		88,723	11,117	1,185	324	28	28,565
Board-Approved CDM Variance Account	1567	0		0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0	0	0	0
RSVA - One-time	1582	(8,767)		(5,986)	(750)	(80)	(22)	(2)	(1,927)
Other Deferred Credits	2425	0		0	0	0	0	0	0
Total of Group 2 Accounts		**94,587**		**64,583**	**8,092**	**862**	**236**	**21**	**20,793**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0		0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0		0	0	0	0	0	0
Total of Account 1562 and Account 1592		**0**		**0**	**0**	**0**	**0**	**0**	**0**
Special Purpose Charge Assessment Variance Account	1521	0		0	0	0	0	0	0
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0							
(Account 1568 - total amount allocated to classes)		0							
Variance		0							
Total Balance Allocated to each class (excluding 1588 sub-account)		**2,299,367**		**1,074,479**	**329,076**	**845,929**	**1,661**	**112**	**48,109**
Total Balance in Account 1588 - sub account		**600,512**		**59,032**	**41,402**	**482,748**	**180**	**0**	**17,150**
Total Balance Allocated to each class (including 1588 sub-account)		**2,899,878**		**1,133,511**	**370,478**	**1,328,676**	**1,841**	**112**	**65,259**

Deferral/Variance Account Workform for 2013 Filers

Please indicate the Rate Rider Recovery Period (in years) | 2

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	200,817,509	$ 1,074,479	**0.0027**	$/kWh
General Service <50 kW	kWh	63,827,597	$ 329,076	**0.0026**	$/kWh
General Service 50 to 4,999 kW	kW	466,442	$ 845,929	**0.9068**	$/kW
Unmetered Scattered Load	kWh	283,437	$ 1,661	**0.0029**	$/kWh
Sentinel Lighting	kW	17	$ 112	**3.2891**	$/kW
Street Lighting	kW	15,101	$ 48,109	**1.5929**	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**$ 2,299,367**		

Rate Rider Calculation for RSVA - Power - Sub-account - Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-account	Rate Rider for RSVA - Power -	
Residential	kWh	17,769,775	$ 59,032	**0.0017**	$/kWh
General Service <50 kW	kWh	12,462,639	$ 41,402	**0.0017**	$/kWh
General Service 50 to 4,999 kW	kW	403,360	$ 482,748	**0.5984**	$/kW
Unmetered Scattered Load	kWh	54,183	$ 180	**0.0017**	$/kWh
Sentinel Lighting	kW	-	$ -	**-**	$/kW
Street Lighting	kW	14,352	$ 17,150	**0.5975**	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**$ 600,512**		

HST DEFERRAL ACCOUNT

During the 2010 IRM application process, the Board directed electricity distributors to record in deferral account 1592 (PILS and Tax Variances, Sub-account HST/OVAT ITCs), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

Pursuant to additional accounting guidance provided in the December 2010 FAQs on the Accounting Procedures Handbook for electricity distributors, WPI has recorded 100% of the HST savings as well as the contra amounts in sub accounts of deferred account 1592 using the transactional basis approach up to December 31, 2011.

Tracking of these accounts will continue until the effective date of disposition at which time the ITC will be reflected in rate base and revenue requirement calculations moving forward. Fifty percent of the confirmed balance will be returned to the ratepayers, which is the balance WPI will be requesting for disposition at a later date. To date, no carrying charges have been calculated on these balances.

Exhibit 9: Deferral And Variance Accounts

Tab 3 (of 4): Smart Meters

SMART METER DEPLOYMENT PLAN STATUS

Westario Power Inc. has completed 90% of its smart meter deployment initiative and is therefore submitting a request to the Board to approve the recovery of smart meter costs as outlined further in this Exhibit. Westario Power Inc. feels that these costs are just and reasonable and sets out to explain such in Schedule 2.

In addition, Westario Power Inc. is seeking approval for rate riders for the stranded assets that are a result of the smart meter deployment. This is evidenced in Schedule 3 of this Exhibit.

SMART METER DISPOSITION RATE RIDER AMOUNTS

MANAGER'S SUMMARY

INTRODUCTION

Westario Power Inc. is submitting this embedded application as part of the 2013 cost of service application for the recovery of the costs the utility incurred in implementing its Smart Meter Program. Westario Power Inc. has now reached the 90% threshold of the audited cost for its program.

As of December 31, 2011, Westario Power Inc. had installed all of their residential and GS<50 Smart Meters. The actual and forecast total smart meter cost claimed in this application is $4.329 million as indicated in Table 1 below.

Table 1 – Summary of Cost Claim

Smart Meter Costs	Actual to Dec 31 2011	Forecast to Dec 31 2012	Total
Capital	3,644,186	325,000	3,969,186
OM&A	259,141	100,844	359,985
Total	$ 3,903,327	$ 425,844	**$ 4,329,171**
	90%	10%	100%

NB: Actual/Forecasted Revenue has not been deducted

The incurred smart meter costs are partially offset (to April 30, 2012) by the Smart Meter Funding Adder – including simple interest – in the amount of approximately $1.0 million. The resulting rate riders and adders being sought are presented in Table 2 below.

Table 2 – Summary of Rate Riders and Adders

Rate Rider	Class	Before	After	Change
Smart Meter Funding Adder (SMFA)	All Applicable Classes	$1.00	-	-$1.00
Smart Meter Disposition Rate Rider (SMDR)	Residential	-	$0.34	$0.34
	GS<50	-	$0.51	$0.51
	GS>50	-	$3.04	$3.04

All costs incurred in completing WPI's Smart Meter Program have been prudently incurred as is evidenced by a per meter cost of $194.85 which is comparable with similar sized utilities. A comparator table is included later in this application. Costs associated with stranded meters have been included in Schedule 3 of this application.

WPI's implementation of Time of Use rates was initially scheduled for June 2011 however, due to technical issues with WPI's SAP platform and the delay of the MDM/R v.7.2 upgrade an extension was granted by the Board. Once WPI overcame its technical challenges, it was able to implement Time of Use rates effective May 1, 2012.

This application is structured in six distinct sections, specifically;

1) Background - Procurement
2) Status of Smart Meter and Time of Use Implementation
3) Capital and Operating Cost
4) Determination of Specific Smart Meter Rate Riders and Adders
5) Summary Rate Change
6) Conclusion

1) BACKGROUND - PROCUREMENT

SMART METER PILOT AND INVESTMENT PLAN

In 2005 as part of its Smart Meter Pilot project, WPI purchased 125 GE Smart Meters to be deployed in the Town of Mildmay.

In December 2006, WPI filed with the OEB a Smart Metering Investment Plan (SMIP) outlining the timeline and expected costs to implement smart metering across its current and future customer base. The SMIP submitted to the OEB is at Attachment 1. Since smart meters manufactured by Elster were used by most of the leading members of the Coalition of Large Distributors (CLD) to meet the provincial Smart Meter Initiative and thus achieve the 2008-2009 Provincial smart meter targets, WPI's SMIP envisaged utilizing these meters also. WPI also made a business decision at that time to no longer use mechanical meters and instead, for new residential services and meter seal expiries, install Elster Rex 2 Smart Meters.

In September 25, 2007, the Ontario Energy Board published a Report of the Board entitled "Smart Metering Initiative: Draft Criteria and Filing Guidelines for Smart Metering Pilots".

The principles of authority permitting a Local Distribution Company (LDC) to carry out its Smart Metering Investment Plan are summarized in the introductory section:

> "Section 53 of the *Electricity Act, 1998* prohibits distributors from undertaking discretionary metering activities, including the installation of smart meters, unless permitted to do so by regulation, a Board order or Measurement Canada requirements. Thirteen electricity distributors have been authorized by regulation to undertake smart meter deployment activities.
>
> Ontario Regulation 427/06 (Smart Meters: Discretionary Metering Activity and Procurement Principles) ("Regulation 427/06") made under the *Electricity Act, 1998*

> provides that any distributor may be permitted to undertake discretionary metering activities under certain limited conditions to test smart meter technologies ("smart meter pilots"). Smart meter pilots must be approved by the Board in advance."

The smart metering pilot project undertaken by WPI in the Town of Mildmay was authorized under a WPI's Third-Tranche Conservation and Demand Management plan. These meters were subsequently written off to stranded meters upon the full implementation of the smart meter program.

SMART METER PROCUREMENT

In 2007, London Hydro led a consortium of 21 LDCs ("London RFP") that released a proposal to solicit pricing and features for a comprehensive Advanced Metering Infrastructure ("AMI"). London Hydro and all of the associated LDCs were bound by the above Draft Criteria and Filing Guidelines for Smart Metering Pilots. They relied on a letter issued on July 25, 2007 by the Minister of Energy, Dwight Duncan, stating:

> "After a successful RFQ, the government will continue to work with London Hydro and consortium members to enable the rollout of smart metering in your respective service territories."

The collaborative initiative assisted LDCs in the development of project plans, RFPs and contract.

Following successful completion of the RFQ process, the Ministry recommended an amendment to Ontario Regulation 427/08 (Smart Meters: Discretionary Metering Activity and Procurement Principles) to Cabinet. The amendments authorized distributors participating in the London RFQ process to engage in discretionary metering activities.

LONDON HYDRO RFP

The London Hydro RFP, structured in phases, was comprehensive in that it asked respondents to showcase their entire range of capabilities.

The first phase required installation of smart meters in a variety of challenging environments:

- Reading Water Meters
- Networked Meters in Apartment Buildings
- Non-networked meters in Apartment Buildings
- Load Shifting in Social Housing Townhouses (electric hot water heaters)
- Difficult Access Meters (Basements)
- Retail Malls (abandonment of Networked Meters)
- Rural
- New Energy Star Homes
- Residential Areas with Known Voltage Regulation Problems

The second phase involved LDC-wide implementation of smart metering. Proponents were asked to evaluate their responses in a tier of four levels:

- Basic Meter Requirements (as per London Hydro's purchasing guidelines and specifications).
- Ontario Ministry of Energy Technical Requirements for Advanced Metering Infrastructure
- London Hydro Supplementary Requirements (i.e. inter-device communication, protocol, security, etc.)
- London Hydro Mandatory and Discretionary Value-added Functionality (Outage management, voltage monitoring, bi-directional meter support), meter tampering notification, demand response, etc.)

LONDON RFP REVIEW OF PROPONENTS

The RFP evaluation scoring was based on a number of criteria which included technical and financial elements. WPI had an opportunity to customize the scoring weighting when the RFP was initially issued (August 14, 2007) to place emphasis on WPI's technical requirements. WPI re-evaluated the results of the scoring on the basis of WPI's unique service territory to determine that its #2 ranked Proponent be awarded the contract. The re-evaluation was further discussed with the utility's legal team and the Fairness Commissioner. Based on the London Hydro AMI RFP process in July 2008, Elster Metering being the "best value (i.e. Life Cycle Value) proponent" was awarded preferred vendor status. WPI signed a Letter of Intent in May 2009 with Elster Metering.

SMART METER PROJECT OVERVIEW OF SERVICES

WPI contracted with various suppliers for supporting services:

- *Energy Axis Management System (EA_MS) Data Collection (2009 - 2012*) – WPI selected Elster to sub contract to Olameter for data collection on WPI's purchased server and software (EA_MS). The decision to have Elster contract this service to Olameter was for system conformability reasons and the successful experience other LDCs had had with Olameter.
- *ODS Data Collection (2010 – 2012)* – WPI selected vendor Metersense developed by North/Star Utilities Solutions– a meter data management application. From billing data to outage and restoration events, performance monitoring to revenue protection, MeterSense collects, manages, stores and delivers Smart Grid information intelligently. This application solution helps the utility reliably and quickly interpret vast quantities of data, and automates the processes that use the data.
- *WAN RFP and award of Contract (2008)* - WPI invited telecommunication companies to quote on the Wide Area Network (WAN) Communications for the Smart Meter project. Bell was successful because of their pricing and ability to provide coverage to our entire service territory.

- *Meter Disposal (2009)* – MCC Industrial Sales was the successful bidder on the price per pound for the meter quotation submitted.

- *Meter Base Repairs (2009)* – Where possible, WPI issued an RFP for meter base repairs and retrofit repairs for the smart meter deployment. Due to the applicants large service territory a list of electricians in each community was maintained in order that they could respond quickly as assistance was required.

- *UtilAssist (2009 – 2012)* UtilAssist provided Project Management and Staff Training with the new Business Process and end-to-end testing with MDM/R as it related to smart meter data flow. In 2012, WPI has engaged the services of Util-Assist, to provide for a Sync Operator role for a period of 18 months. The Sync Operator role provides various services such as Daily Validation of overall performance of the network, identify and resolve exceptions within the network by way of the LDC or Head End administrator(s), daily performance reports and delivering them to utility personnel, monitor data synchronization between CIS, Head End system, MDM/R and ODS, monitor and resolve Billing Quantity Request exceptions from MDM/R and CIS and development, configuration and testing of rules for the ODS Rules Engine.

- *Residential Installation Service Provider (2009 – 2011)* – WPI issued an RFP to various meter installation service providers. The contract was awarded on pricing to Olameter.

- *Commercial Installation Service Provider (2010 – 2011)* WPI issued an RFP to various meter installation service providers. The applicant chose Rodan based on their ability to meet the technical requirements, trained personnel and scope of the contract.

- *Web Presentment (2012)* – After WPI reviewed presentations from four vendors; the applicant awarded the contract to Whitecap. This decision was based on the endorsement of the Electricity Distributors Association and on an internal evaluation by WPI management.

- *Security Audit* - In January 2011 WPI was part of a consortium co-ordinated by Util-Assist that consisted of 16 LDCs using Elster meters. This consortium was formed to retain the services of a cyber-security company, specifically for the purpose of auditing data transmission security of customer data across the Elster network. WPI chose to participate in this consortium to ensure the safety and integrity of WPI customer data together with endeavoring to prove the utility's continuing due diligence on this very high profile and sensitive subject. Subsequent to the formation of the consortium, two additional LDCs joined which brought the group to a total of 18 members. N-Dimensions was chosen as the successful bidder to complete the security audit.

In 2009, after a thorough review of Elster's final propagation study of WPI's diverse service territory, orders were placed for 21 collectors and 2 repeaters and installed in 2009. Meter orders began to be placed in the summer of 2009 with delivery commencing shortly after that.

2) STATUS OF SMART METER AND TIME OF USE IMPLEMENTATION

WPI installed approximately 90 GE smart meters as part of a pilot project in 2005 for its Residential customers in the Village of Mildmay. The Ministry of Energy mandated that all residential and small businesses in Ontario have a smart meter installed by the end of 2010. WPI's 1st phase was deployed in July 2009. There were a total of 13,671 meters installed in 2009 and 5,718 meters were installed in 2010; with full implementation completed in 2011 with the final 2,589 meters being installed. The 21,978 meters installed to the end of 2011 represented 100% of WPI's Residential and General Service < 50 kW (GS<50kW) meters.

Projected 2012 operating costs include monthly fees for EA_MS software maintenance, WAN maintenance, ODS maintenance, Elster administrative costs, security audit costs, meter maintenance, CIS software maintenance, customer education mail out, communication costs and MDM/R-IESO costs.

Approximately one-third of the General Service > 50kW (GS>50kW) meters are scheduled to be replaced in 2012 with costs forecasted under the smart meter capital expenditures. The remaining approximately two-thirds of GS>50 meters will be replaced in 2013 and 2014 with costs for the 2013 meters incurred in the rate base applied for in this Application and the 2014 meters will be submitted for consideration in a future rate application as per the IRM and cost of service application guidelines.

In an effort to meet its mandated TOU implementation deadline of July 2011, the installation of smart meters was given very high priority by the company's senior management.

Table 3 below shows the actual number of smart meters installed per year with 100% installation of residential and GS<50 customers (21,978 smart meters) completed by end of 2011. As will be subsequently discussed, 80 smart meters for WPI's GS>50kW customers will be installed as part of the program.

Table 3: Schedule of Actual Installation of Smart Meters

Customer Class	2009	2010	2011	2012
Residential	12,799	5,146	1,575	-
GS<50	872	572	1,014	-
GS>50	-	-	-	80*
	13,671	5,718	2,589	80

* - forecast to be replaced in 2012

With respect to the installation of smart meter for the GS>50 customers, the Board's Guideline G-2011-0001, at page 16, states that:

> Some distributors may be doing "smart meter" conversions for General Service > 50 kW customers upon repair or resealing to enable meter data collection through the AMI infrastructure. While it is recognized that these smart meter installations and conversions are beyond minimum functionality, a distributor may apply for the recovery of such costs. The application should document the nature, the justification and the cost per meter separately from those for the residential and GS < 50 kW customers.

While recognizing that installation of smart meters for GS>50kW customers was technically beyond minimum functionality, WPI determined that the only prudent course of action was to install smart meters rather than continue to recertify and replace older technology. The applicant concluded that installing smart meters for this customer class made good business sense, for which the key factors supporting the installation of smart meters for the GS>50kW customers were:

- Changing out virtually a complete bank of meters so that they could be read remotely while leaving only one or two meters which required to be read manually would result in a grossly inefficient meter reading operation.

- GS>50kW customers have loads which could potentially fall into the GS<50kW customer class and vice-versa; therefore, it is not prudent to wait and only change the meter if and when the actual customer designation changed. (For example; in 2011 WPI changed 7 of its 260 (i.e. 3%) in the GS>50kW customer class were *below* the GS<50kW / GS>50kW threshold for virtually the whole year. However, because the load for these customers crossed above the threshold occasionally (often only for one month in the year), they *had* to be classified as GS>50kW customers so these customers would be charged for peak demand load. Thus, there is a significant potential for many of the GS>50kW customers to be re-classified at any time as GS<50kW customers; when this occurs the installation of smart meters becomes mandatory.

- Providing the GS>50kW customers with a smart meter would provide these customers with peak and energy-saving opportunities consistent with the Government's Conservation and Demand Management objectives and allow WPI to better monitor existing and future load to ensure system optimization opportunities.

Pursuant to the Guidelines WPI has separately tracked and documented the cost per meter for the GS>50 kW customers, and asked that those costs be allowed as cost beyond minimum functionality through an SMDR.

WPI implemented Time of Use pricing for its Residential and GS<50kW customers effective May 2012.

WPI's TOU implementation proceeded on plan per the schedule shown below.

	METER READING	TOU BEGIN	REQUESTED	TOU BEGIN	FIRST TOU
RATE CLASS	UNITS TO BE BILLED	READ DATE	USDP	BILL DATE	BILL MAILED
RESIDENTIAL					
KI	RESKI	29-Feb-12	01-Mar-12	01-May-12	13-Jun-12
LU	RESLU	29-Feb-12	01-Mar-12	01-May-12	15-Jun-12
RI	RESRI	29-Feb-12	01-Mar-12	01-May-12	13-Jun-12
PE	RESPE	29-Feb-12	01-Mar-12	01-May-12	19-Jun-12
SO	RESSO	29-Feb-12	01-Mar-12	01-May-12	19-Jun-12
TE	RESTE	29-Feb-12	01-Mar-12	01-May-12	15-Jun-12
WI	RESWI	29-Feb-12	01-Mar-12	01-May-12	15-Jun-12
MI	RESMI	29-Feb-12	01-Mar-12	01-May-12	20-Jun-12
WA	RESWA	29-Feb-12	01-Mar-12	01-May-12	20-Jun-12
NE	RESNE	29-Feb-12	01-Mar-12	01-May-12	25-Jun-12
HA	RESHA	29-Feb-12	01-Mar-12	01-May-12	26-Jun-12
EL	RESEL	29-Feb-12	01-Mar-12	01-May-12	19-Jun-12
CL	RESCL	29-Feb-12	01-Mar-12	01-May-12	21-Jun-12
HR	RESHR	29-Feb-12	01-Mar-12	01-May-12	25-Jun-12
PA	RESPA	29-Feb-12	01-Mar-12	01-May-12	21-Jun-12
GS LESS THAN 50					
GS	GSLS50	29-Feb-12	01-Mar-12	01-May-12	25-Jun-12

3) CAPITAL AND OPERATING COSTS

AUDITED COSTS

The Guideline states that the Board expects the majority of the total program costs for which the distributor is seeking recovery will be audited. In the early preparation of this application, WPI determined that 90% of the total program costs for which recovery would be sought had been already audited as part of its 2011 audited financial statements and the balance will be included in its 2012 audited financial statements.

CAPITAL AND OPERATING COSTS

In this application, WPI is seeking recovery for the 21,978 smart meters installed in its service area at the end of 2011 as well as the additional 80 GS>50 smart meters to be installed in 2012. Apart from installing meters for new customers in 2012 and beyond, smart meter installation is complete. The capital expenditures planned for 2012 and beyond that is included for recovery in this application is monies for installation of 80 GS>50 meters and programming and implementation costs for the customer presentment tool (powered by WhiteCap) and TOU. Table 4 provides a summary of the actual costs to 2011 and the forecast costs to the end of 2012.

Table 4 – Summary of Cost Claim

Smart Meter Costs	Actual to Dec 31 2011	Forecast to Dec 31 2012	Total
Capital	3,644,186	325,000	3,969,186
OM&A	259,141	100,844	359,985
Total	$ 3,903,327	$ 425,844	**$ 4,329,171**
	90%	10%	100%

NB: Actual/Forecasted Revenue has not been deducted

Full details of the various cost components by year are shown in Sheet 2 of the Smart Meter Model (located at Exhibit 9, Tab 2, Schedule 3, Attachment 2).

Table 5 on the following page provides an intermediate-level break down of the summary costs shown above.

Table 5: Smart Meter Costs Claimed for Recovery

Cost Element	Cost Sub-Elements	Total Costs
Capital	1.1 Advanced Metering Communication Device	$3,485,224
	1.2 Advanced Metering Regional Collector	$58,963
	1.3 Advanced Metering Control Computer	$150,000
	1.4 Wide Area Network	$Nil
	1.5 Other Capital Costs Related to Minimal Functionality	$Nil
	1.6 Capital Costs Beyond Minimum Functionality	$275,000
	Total Smart Meter Capital Costs	**$3,969,187**
OM&A	2.1 Advanced Metering Communication Device	$194,299
	2.2 Advanced Metering Regional Collector	$Nil
	2.3 Advanced Metering Control Computer	$Nil
	2.4 Wide Area Network	$Nil
	2.5 Other AMI OM&A Costs Related to Minimal Functionality	$165,686
	2.6 OM&A Costs Related To Beyond Minimum Functionality	$Nil
	Total Smart Meter OM&A Costs	**$359,985**
TOTAL	**TOTAL SMART METER COSTS**	**$4,329,172**

NB: Actual/Forecasted Revenue has not been deducted

The resulting WPI cost per smart meter is $194.85 which is comparable to like utilities as outlined in Table 6.

Table 6 – Cost per Smart Meter – Comparator Utilities

Comparator Utilities - Cost per Meter						
	Chatham-Kent	Erie Thames	Halton Hills Hydro	Lakefront	Norfolk	Westario Power Inc.
Total smart meter cost	2,026,782	3,527,457	4,908,983	2,110,595	3,895,896	4,329,171
# of Customers	31,703	18,904	21,542	9,833	19,303	22,218
	$ 63.93	$ 186.60	$ 227.88	$ 214.64	$ 201.83	**$ 194.85**

In its 2009 cost of service application (EB-2008-0250), WPI stated that it intended to install approximately 19,125 meters during the 2010 test year at an estimated cost per meter of $216.65 and total cost of $4,143,612. WPI did not include any capital costs for smart meters in its rate base at that time, nor had it including operating expenses related to smart meters in its revenue requirement at that time. It should therefore be noted that Westario was very prudent in keeping costs in line to what was initially budgeted.

There are some factors for Westario Power that can be identified as drivers for incurring higher costs than that of larger utilities. A major challenge that Westario Power Inc. faced with respect to the installation of our smart meter program is that the geography of our territory required additional collectors and repeaters. In addition, the installers were required to travel from one community to the next and therefore higher costs were incurred for down time. WPI incurred significant consulting costs which were required as a result of not having the expertise in-house to conduct the single-most largest project in Westario's history. Additional costs related to changing GS<50 meters were incurred as the meters in our territory were not uniform and various bases and adaptors were required. Poor meter data in the applicant's CIS system resulted in inconsistent information between what was in the CIS vs. the type of meter installed at the customer premise. In some cases, this inconsistency resulted in multiple visits by the installation contractor to ensure the correct meter would be installed.

Although WPI did incur significant costs for consultants, the consultation enabled WPI to conduct the project in the most cost effective manner will maintaining efficiencies. In fact, WPI at various points in the project partnered with other utilities to gain savings and share ideas and issues with other utilities.

WPI submits that its total program costs and thus its cost per installed meter are reasonable and were prudently incurred.

INCREMENTAL COST SAVINGS

While the installation of smart meters has increased the operating cost of WPI, certain offsets have resulted. The most significant of these is the virtual elimination of manual meter reading for which the cost to WPI has been reduced accordingly. This is also the main driver for changing the meters for our GS>50 customers to smart meters as additional cost savings will result. WPI has approximately 240 GS>50 customers and has a three year plan in place to change the meters to smart meters. WPI will install the first batch of 80 smart meters under this smart meter program and the remaining 80 per year (2013 and 2014) will be installed under our capital expenditure budget.

VARIANCE ANALYSIS

Although an interim recovery was permitted in earlier guidelines, WPI did not previously apply to the Board for partial recovery of its smart meter costs after it had installed 50% of its smart meters. Accordingly, a variance analysis comparing actual costs to previously-approved recovery of costs has not been performed.

MINIMUM FUNCTIONALITY

WPI installed Elster smart meters for all residential customers and small commercial customers (i.e. GS<50). The residential Rex 2 meters slightly exceeded the specifications adopted in O.

Reg. 425/06; however, they were the most basic meters manufactured as a standard item. To have acquired Rex 2-type meters that *just* met the minimal functionality requirement would have resulted in additional customization to "de-rate" the standard Rex 2 meters. In other words, it was less expensive to purchase the standard Rex 2 meters (with slightly enhanced functionality) than to purchase a customized version that just met the minimal functionality level. The Elster A3RL smart meter provides the ability to read the usage of all the commercial customers. Acquiring a single type of meter for all such customers was the most prudent business decision.

The costs that WPI incurred for TOU rate implementation, CIS system changes, web presentment, bill presentment, integration with MDM/R, etc. were the minimal costs necessary for implementing the smart meter program and a functioning TOU system. All costs claimed in this application are strictly incremental; that is, they are the essential minimal costs necessary to meet the Government's smart meter mandate. No cost is included for which the Smart Meter Entity has exclusive authority to act pursuant to O. Reg. 393/07. Costs incurred for materials and/or parts for customer-owned equipment (e.g. repairing meter bases that were damaged in the process of removing the existing meters) were expensed and tracked separately.

COSTS BEYOND MINIMUM FUNCTIONALITY

As noted, smart meters will be installed for WPI's GS>50kW customers. Although not included in the regulation to change these customers to smart meters, an important component of the rationale to do so was the significant potential for GS>50kW customers to cross over the GS<50kW / GS>50kW threshold and thus the installation of a smart meter would have been mandatory. Another deciding factor was to reduce meter reading costs by eliminating manual meter reads. The capital cost for this 2012 initiative is $250,000 for 80 meters. It is expected that the board will approve the costs of the smart meter project as it relates to GS>50 customers and that the costs will be spread across all GS>50 customers.

WPI has budgeted $15,000 for costs related to the programming and implementation of a web presentment tool. These costs, although not specifically identified as a cost permitted by regulation, will be incurred as a smart meter project cost in 2012. WPI feels that this tool will provide significant enhancements to customer satisfaction by enabling customers to view reports and consumption patterns, which the Applicant anticipates will further encourage cost saving initiatives by changes to consumption patterns. WPI would not have had an opportunity to provide this level of service without the smart meter installation program.

SUMMARY OF COSTS

WPI submits that the selection of the Residential and commercial meters was eminently reasonable, prudent and a sound business decision that minimized the cost for all its customers.

4) DETERMINATION OF SPECIFIC RATE RIDERS AND ADDERS

In the Board's March 21, 2006 Decision (RP-2005-0020, EB-2005-0529) local distribution companies that had not already installed smart meters were allocated advance funding equivalent to $0.30 per *residential* customer per month. The advance funding was provided in the form of a Smart Meter Funding Adder (SMFA) which was spread across all *metered* customers thus reducing the actual amount included in all metered customers' bills to generally between $0.25 to $0.28 per metered customer per month.

In the Board's April 12, 2007 Decision (EB-2007-0591) on WPI's 2007 rates, a $0.26 SMFA was applied to all metered customers and embedded in the monthly Service Charge beginning May 1, 2007.

The $0.26 SMFA amount continued to be embedded in WPI's customers' rates until the Board's April 24, 2009 Decision and Order (EB-2008-0238) on WPI's 2009 rates when the amount for the embedded SMFA was adjusted to $1.00 per metered customer per month effective June 1, 2009. This SMFA continued until April 30, 2012, as noted in the Guideline, page 20.

Table 7 below shows the actual and forecasted SMFA revenue. Simple interest is included. Details are included in the Smart Meter Model attached as Exhibit 9, Tab 3, Schedule 3, Attachment 2 – Sheet 8.

Table 7: Actual and Forecasted Smart Meter Funding Adder Revenue

Year	SMFA Revenue
2006	$53,012
2007	$91,762
2008	$73,302
2009	$199,167
2010	$266,733
2011	$276,996
2012	$126,787
Total	**$1,087,760**

COST ALLOCATION

In preparing this application, WPI allocated the capital and operating costs being claimed for recovery across its three metered classes as recommended by the Guideline. As detailed records exist for the smart meters acquired for each of the three metered classes, an accurate allocation of the balance of the capital costs together with the operating expenses was determined and thus a separate rate rider value for each applicable class has been determined for the Smart Meter Disposition Rate Rider (SMDR).

SMART METER DISPOSITION RATE RIDER (SMDR)

WPI is seeking Board approval for a Smart Meter Disposition Rate Rider in the amount of $0.34 for residential metered customer per month, $0.51 for GS<50 metered customers per month and $3.04 for GS>50 customers per month for the 3.67 year period May 1, 2013 to December 31, 2016. The calculation was made utilizing the Board's Smart Meter Model (as referenced above).

The value of the SMDR is based on the net amount resulting from:

- Deferred and forecasted Smart Meter Incremental Revenue Requirement from January 1, 2007 to April 30, 2013

Plus

- Interest on Deferred and forecasted OM&A and Amortization Expenses from January 1, 2007 to April 30, 2013

Less

- SMFA Revenues collected per customer class (including carrying charges) from May 1, 2006 to April 30, 2013

Table 8 below shows the calculation of the SMDR. Full details are contained in the Smart Meter Model which is attached to this Tab.

Table 8: Smart Meter Disposition Rate Rider

	Total	Residential	GS<50	GS>50
Deferred and forecasted Smart Meter Incremental Revenue Requirement	$1,444,738			
Interest on Deferred and forecasted OM&A and Amortization Expenses	$25,722			
Deferred Incremental Revenue Requirement	**$1,470,460**			
Smart Meter Rate Adder Revenue	$1,042,388			
Carrying Costs	$50,480			
SMFA Revenue Collected	**$1,092,868**			
Net Deferred Revenue Requirement	**$377,592**			
Metered Customers		19,520	2,458	240
Weighted Percentage By Class		80%	13%	7%
Smart Meter Disposition Rate Rider (SMDR)		$ 0.34	$ 0.51	$ 3.04

5) RATE CHANGE SUMMARY

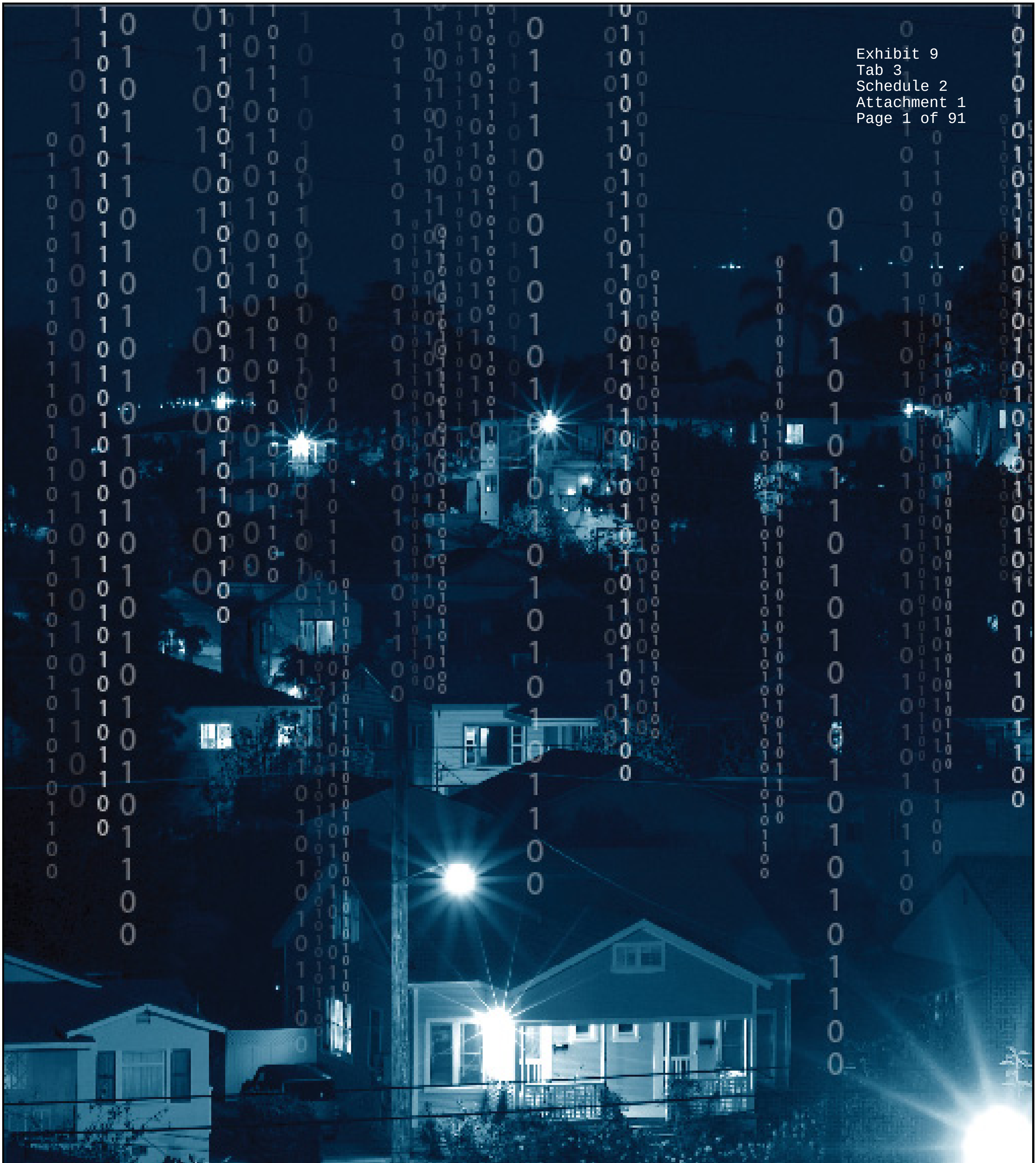
Table 9 below shows the $0.34 residential, $0.51 GS<50 and $3.04 GS>50 rate change that WPI is seeking approval for in this application. The "before" value corresponds to the most recently approved values; i.e. those contained in Appendix A to Decision and Order, Tariff of Rates and Charges, EB-2010-0122, dated April 14, 2011. As per Decision and Order, EB-2011—0205 dated April 19, 2012, there was no provision for a smart meter rate adder.

Table 9: Summary of Smart Meter Rate Changes

Rate Rider	Class	Before	After	Change
Smart Meter Funding Adder (SMFA)	All Applicable Classes	$1.00	-	-$1.00
Smart Meter Disposition Rate Rider (SMDR)	Residential	-	$0.34	$0.34
	GS<50	-	$0.51	$0.51
	GS>50	-	$3.04	$3.04

6) CONCLUSION

It is respectfully submitted that the costs requested for recovery in this application have been necessary to fulfill WPI's obligations under the Provincially-mandated Smart Meter Initiative; have been prudently incurred in accordance with Board guidelines; the proposed rate rider are just and reasonable; the associated customer bill impacts are minimal; and it is therefore appropriate that the Board approve the proposed rate rider for implementation effective May 1, 2013.



CornerstonE
Hydro Electric Concepts

Smart Meter Investment Plans

Board File Number EB 2006-0246

December 15th, 2006

Prepared in conjunction with
Util-Assist Inc.

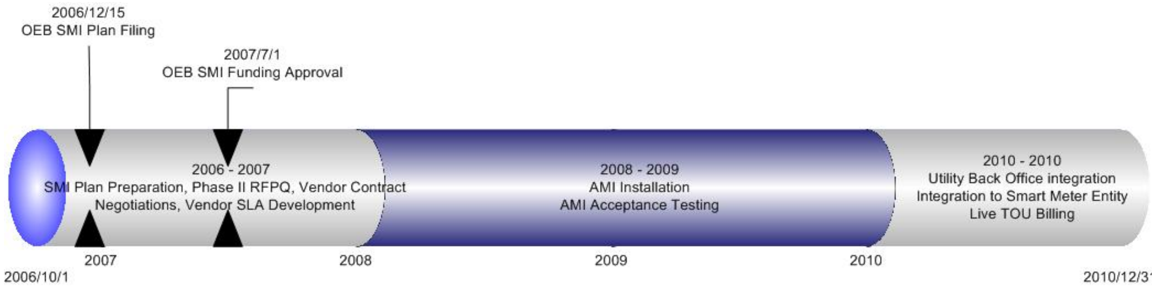
Executive Summary

Cornerstone Hydro Electric Concepts (CHEC) members are pleased to provide the Ontario Energy Board (OEB) our plans for smart meter investment in the 2006 rate year (May 1, 2006 to April 30, 2007). Our association is working together to collectively prepare and fulfill the requirements of the OEB and the Ministry of Energy regarding the Smart Meter Implementation Plan.

This is an enormous undertaking for all Local Distribution Companies (LDCs); a project that will take months of planning and carefully managed execution. To accommodate the needs of the Ministry of Energy (MOE) and the Ontario Energy Board, CHEC members will have to install approximately 142,000 meters by the end of 2010.

The required network is new to this market, and the rules that will be established will also be unique. Clearly the Smart Meter Initiative (SMI) is an all-encompassing program, with implications for every utility system. Many of the components of the SMI fall under the responsibility and control of the utility, while others will be in the hands of regulatory bodies. Regardless of who is in control of each component, a comprehensive, effective, and achievable implementation plan will need to consider all aspects. For CHEC members to seamlessly integrate their chosen Smart Meters; their planning will need to take into consideration the functionality of all required systems, so that preparation for future integration has been properly considered.

Specific to the OEB filing requirements relating to smart meter investment plans, **No CHEC members have plans to procure and install smart meter infrastructure in the 2006 rate year (May 1, 2006 to April 30, 2007)**; with each CHEC member developing the details of their multi year plan in 2007 and following the timeline below for implementation.



The following pages contain a carefully considered process, which identifies generic steps that will be followed by CHEC members at utility specific time intervals. We feel the structure of this document will allow the OEB to understand the direction each CHEC member intends to follow in the development and completion of their smart meter investment plan for current and future rate years. This group process will allow members to partner with and learn from each others deployments helping mitigate deployment risks to the rate payers in our service territories.

Introduction

The provincial government has mandated installing a smart electricity meter in every Ontario home by December 31, 2010, The Ontario Energy Board in its decision on generic issues (EB-2005-0529) related to the smart meter initiative filed its decision, dated March 21, 2006 which stated:

> "In addition, as a condition of granting the rate applications, all utilities will be required to file with the Board within 90 days of this Decision their plan for smart meter investment in the 2006 rate year."

The subsequent Regulations were issued on September 16, 2006. Accordingly, the Board will require distributors to file their plans (File No. EB-2006-0246) for smart meter investment in the 2006 rate year (May 1, 2006 to April 30, 2007) by December 15, 2006 (within 90 days of the issuance of the Regulations).

In order for Ontario LDCs to develop these investment plans they will need to understand how all of the AMI systems that have been pre-qualified work, and how they should be structured to meet the needs of the Ontario government. The business case for supplementary functionality will need to be created so utilities can make decisions on AMI systems qualified within the selection framework, as recovery of the asset will be based on the minimum Functional Specification requirements. Proper analysis will help minimize risk from both an operational and financial perspective.

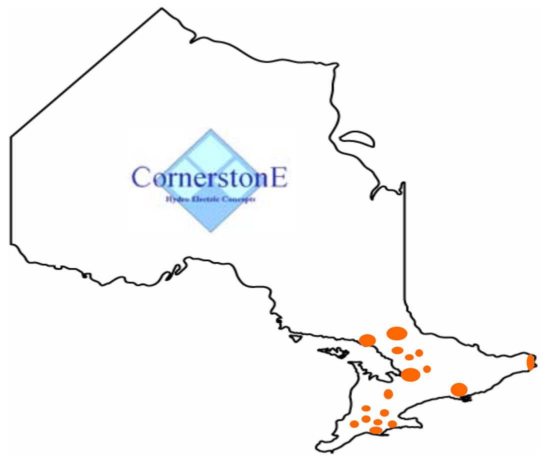
Upon selection of an AMI provider, and confirmation of final pricing for each CHEC service territory, the installation process will need to be properly addressed. Plans that will need to include acceptance testing of installed technology will need to be addressed to ensure that the deployed product achieves the performance goals and that the asset is properly integrated into all departments within the utility.

The 3rd Party Installation vendor which utilities may select for this process will represent the utility in the eyes of the public, and must perform this task at the highest level of quality and safety. In making this important decision, Best Practice installation procedures must be considered (recording of GIS coordinates, digital image of off-reads, etc), utilization of Workforce Management systems (WFM), disposal of old meters, and most importantly the investigation into safety requirements for the associated field services. By working together with neighbouring utilities, and through working group relationships, CHEC members are in the ideal position to understand and properly address any potential scheduling conflicts that could alter the quality of the service provided by vendors. Carefully controlled analysis will help minimize risk from both an operational and financial perspective. The process enlisted by the CHEC group would ensure that the best possible staff is utilized for each installation, and that each individual utility is properly represented to their end consumer.

The decision making process regarding the Smart Meter Initiative needs to be well documented. Documentation will reflect the analysis that go into this important decision by noting the service available, as well as the pricing and associated risk of short-listed vendors. A well organized approach will ensure the proper decisions are made, and that the approval to move forward is achieved.

Cornerstone Hydro Electric Concepts (CHEC)

The CHEC Group is an association of sixteen electricity distribution utilities modeled after a cooperative to share resources and proficiencies as the Ontario electricity industry continues its transformation. Previously known as the Organized Power Group, the CHEC group has expanded its membership and subsequent customer base resulting in a diverse yet collective alliance focused on maximizing value for investment by combining resources and competencies while simultaneously maintaining the high standards of locally supplied service our customers have come to expect.

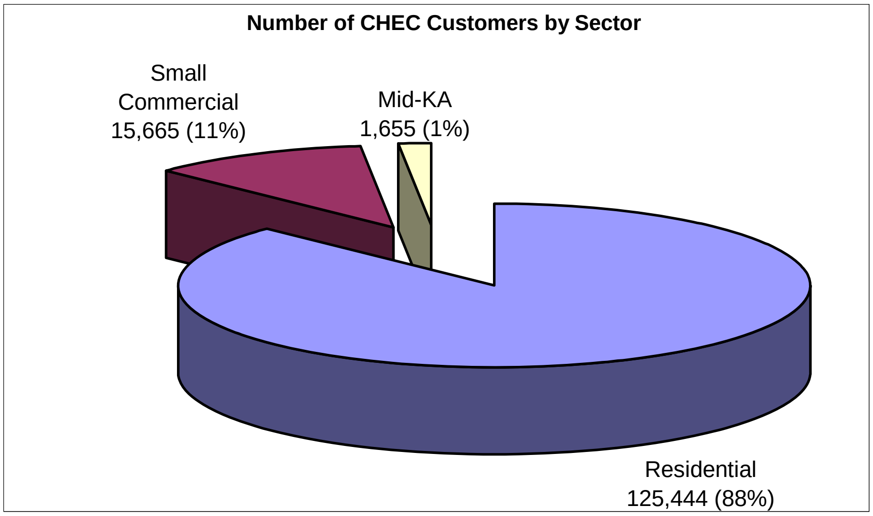


The mission of the CHEC Group is to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources. The values of the CHEC Group include the sharing of resources, both intellectual and technical, enabling members to deliver value to their customers and shareholders ensuring competitiveness in the marketplace. Together the mission and value statements represent lofty but attainable goals for the CHEC Group.

To accommodate the needs of the Ministry of Energy, the CHEC group will need to install approximately 142,000 meters by the end of 2010. Combined with the sheer magnitude of the Smart Meter Initiative, the CHEC group (in keeping with the philosophy of a cooperative) also has the challenge of choosing technologies for deployment over varied terrain, all the while trying to achieve savings through shared infrastructure wherever possible.

The CHEC Group represents in excess of 142,000 customers with the majority classified as residential sector (88%) and the remaining small commercial and mid-market/key accounts, representing 11% and 1% respectively. See Table 1.

Table 1: CHEC Group Customer Sector Summary



Annual energy consumption is in the neighbourhood of 3,000 GWh. See Table 2 below for further detail.

Table 2: CHEC Group Annual Consumption (kWh) Summary

CHEC Group Annual kWh Summary			
Residential Sales	**Small Comm.**	**Mid & KA Comm.**	**Total Sales**
1,252,780,897	490,071,034	1,532,928,045	3,275,779,976

Comprised of LDC's from across southwestern, central and eastern Ontario the target audience of CHEC Group initiatives is wide ranging and fully represents the diversity in Ontario economically, geographically and culturally. Diversity of the CHEC Group has been given full consideration in the development of this Smart Meter Plan.

Member LDC's will benefit from this joint effort in planning through the pooling of volumes in procurement processes for services such as Installation and Meter Disposal, and potentially through purchases of ancillary products like meter bases, and adaptors which may be required to accommodate the large volume of installations.

This report represents a joint submission on the issue of Smart Meter Initiative planning by the members of the CHEC Group in consideration of our collective responsibility to "…act as agents of change at the local level to promote conservation."

Assumptions

The CHEC group has created the following plan under the assumption that the costs described herein will be recoverable. If the costs as described are not going to be recoverable, some components of this plan may change.

CHEC Strategy

With the need for mass deployment rapidly approaching, the strategy of the CHEC group is to work together and create a process that accomplishes the goals of the Smart Meter Mandate, while controlling the risks to our customers and share holders.

The path that will be followed by the CHEC members is to procure the AMI infrastructure through an approved process identified by the following Ontario Regulations regarding the Electricity Act, 1998;

Reg. 425/06 Criteria and Requirements For Meters and Metering Equipment, Systems and Technology,
Reg. 426/06 Smart Meter: Costs Recovery and,
Reg. 427/06 Smart Meters: Discretionary Metering Activity and Procurement Principles, AMI Functionality

These approved processes include the Coalition of Large Distributors (CLD) RFPQ in conjunction with the MOE, the Hydro One procurement process, or any future MOE approved procurement processes.

For the purposes of this filing the deployment strategy identified by the group can be segmented into the following generic steps;

Planning
Procurement Process / Vendor Selection
OEB Rate Approval
Negotiation with Qualified Vendors
Customer Communication
Implementation
Meter Disposal
Acceptance Testing
Security and Authentication
Back Office Integration
Customer Presentment

Planning

During this stage the approach by CHEC members will be to produce detailed project plans regarding the smart meter initiative, identifying all tasks that need to be completed as well as the resources required to achieve these tasks. Part of this planning process will include understanding and collecting the information required by the qualified AMI (meter types, propagation studies) and installation vendors (location types i.e. inside outside, rural, etc). With this information utilities will be well positioned to gather budgetary numbers that will be used for rate approvals (for those members that have yet to file their smart meter rate request). This approach ensures all costs are properly understood to help verify the funding requirements of each CHEC member. By identifying the technical requirements, timelines, and estimated costing, the main goal of this section is accomplished by ensuring realistic timelines are created and an achievable plan presented.

Procurement Process / Vendor Selection

CHEC member's selection and procurement process can identify and take advantage of the opportunities of price offerings by Phase One utilities or procure a technology that has yet to be selected in the Ontario Market (forthcoming Phase 2 procurement process). If the latter is the process required by the MOE and CHEC members, a thorough procurement process will take place, potentially including the involvement of consultants and fairness commissioners to create a seamless process. The end goal of such a process would be to produce a list of qualified vendors with which CHEC members could enter into final vendor negotiations and subsequent selection.

OEB Rate Approval

During the Procurement / Vendor Selection stage each CHEC member will make their detailed rate filing with the OEB. This filing will have costs associated with approved technologies based on information made available from vendors and phase one utilities. It is critical that CHEC members completely understand the rate approval process and the associated recovery allocation before they enter into final negotiations and contract signing with qualified smart meter vendor(s). This process is expected to take four months to complete from the time the file is submitted to the OEB. Without rate approval, the next stages of the smart meter implementation process will be delayed.

Negotiation with Qualified Vendors

Having acquired a level of comfort regarding the functionality of the qualified vendors considered appropriate for mass deployment, CHEC members will invite these vendors into a final negotiation session. In this meeting, final pricing relating to the specific deployment details of each CHEC member are addressed. This process will also identify the risks associated with each company. These meetings are considered extremely important as they will result in true costing of the AMI system as well as the opportunity to identify all deliverables which will help finalize the Implementation deployment plan that each Member is managing.

Customer Communication

The success of the smart metering implementation and the switch to TOU rates may be more dependent on the effectiveness of our communications planning than any other portion of our strategy. First and foremost, all of our staff must be educated ambassadors for smart metering and TOU. We must be able to explain how this new technology will assist in managing current and future residential energy consumption practices and be aware of the status of the implementation and deployment progress.

All employees will need to attend Smart Meter Information Sessions to learn about the purpose of smart meters, the way in which the meters operate, details of our Smart Meter Communications Plan, and time-of-use rates. Customer service representatives may need to receive more in-depth training than other employees as they will be required to respond to questions from the public.

During mass deployment, materials for our customers must be consistent with messaging from the MOE, and the OEB. A selection of smart meter materials needs to be designed and purchased by LDCs for use in two stages: pre-smart meter installation and post-smart meter installation. The purpose is to ensure consistent messaging on the topic of smart meters.

Implementation

The first priority will be to ensure that all field processes and safety procedures are well documented; ensuring implementation is performed safely and without incident. CHEC members will maximize the value of the site visit while maintaining the highest level of quality to help control the need for return visits which will increase overall costs. Any opportunities that are presented which can improve the installation process should be strongly considered, once it is determined what the priorities are with respect to this process.

Other considerations that are affected by the anticipated time for deployment include the method of data entry for the meter changes that are performed, and possible ways of avoiding potential customer disputes regarding "off-reads". Workforce Management systems and Digital Images (for storage of "off-reads") are just two examples of how this process can be controlled, with supplementary benefits such as improved safety procedures through the use of these solutions.

CHEC members will jointly develop the plans that will see tasks grouped by associated departments (Metering, Customer Service, IT, Procurement, and Executive Management teams). This format will prove valuable in managing the hundreds of tasks required of the Smart Meter Initiative. Buying pools will be researched, and financial options will be investigated to determine applicability to the CHEC members.

Meter Disposal

Accompanying the challenges of determining the right technology fit, labour considerations, and back office integration, is the problem of disposing of the redundant meters. Perhaps more importantly than the cost of the disposal of the meters, is the environmental and political considerations associated with this process. The new technology is required to accommodate the end goals of the government, but dumping millions of meters into landfill sites is not necessary, and therefore not considered an option by the CHEC group. By researching alternative avenues of disposal, CHEC has found that the potential environmental and political backlash associated with the projected 27 million pounds of scrap (produced through the Smart Meter Initiative) can also be avoided through recycling processes.

Acceptance Testing

During the later stages of implementation, test scripts will be executed on the systems as they are deployed to ensure that the proper amount of infrastructure has been installed to accommodate the performance requirements of the industry. Acceptance testing will be initiated to ensure that the infrastructure is operating according to the requirements, thereby minimizing the risk associated with mass deployments.

Security and Authentication

With the introduction of AMI systems, utilities will become susceptible to new levels of potential security breaches. By installing network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that utility data, and equipment, are kept secure from manipulation, or other forms of control. Industry reports show a worldwide trend in cyber security breaches from "hacking" where the utilities are the recipients of extortion threats.

The minimum Functional Specification for an Advanced Metering Infrastructure (AMI) released in July 2006 identified the need for security within the AMI network - Section 2.11 Security and

Authentication: "The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements."

As members of the OUSM working group, CHEC utilities have embarked upon an educational process which has included partnering with Industry experts to provide qualified, objective, third party security viewpoints. The goal thus far has been to gain the knowledge required to build security into smart meter systems at the foundational level, which is a fundamental Best Practice. An annual evaluation (using standard test scripts) will be performed by an approved third party, providing a comprehensive security assessment of all CHEC members' AMI systems.

Back Office Integration

The integration of the data being acquired from the chosen AMI system(s) into daily processes is a critical component in ensuring that operational efficiencies are maximized by the chosen system. Clearly the Meter Data Management/Repository (MDM/R) will become an integral piece of technology; interfacing with the CIS for the purposes of billing as well as to other operational entities that may be interested in using the information acquired from the AMI network. The CHEC group understands that the Meter Data Repository will be a centralized entity. It will be important for CHEC members to work with AMI Operational Verification Tools for the purpose of evaluating the performance of the AMI network until the AMI infrastructure is live within the centralized MDM/R. As part of their commitment to the successful implementation of the Smart Meter deployment and systems integration, the CHEC group has a representative working with, and on, the IESO Smart Meter System Implementation Plan workgroup.

The time line followed by each CHEC member in going live with TOU billing takes into consideration the timing required for system set-ups, configuration and testing associated with TOU billing each members CIS system.

Customer Presentment

With the drastic changes in our energy market, there is a growing emphasis on conservation and consumer education. Traditionally, the problem faced by the end consumers is the lack of information regarding the daily use of electricity.

To effectively educate end users on their consumption habits, a technology infrastructure will need to be implemented that will provide granular information regarding consumer usage over the course of a day. This new information combined with innovative pricing structures such as time of use will help motivate changes to a consumers usage patterns.

The concept of conservation is not restricted to WEB presentment of information. Multiple technology solutions will be required to effectively communicate the message that is being advocated through this initiative. WEB presentment is not the only way to communicate this message, but should instead be considered one of many tools to be implemented in the network. IVR systems and bill print modifications should be explored and other forms of media will be required to ensure the message is communicated effectively to all customers.

Every consumer has the right to conservation. While the end result should be an easy to use tool that will present this concept to the consumers in a logical format, the functionality that will be required in presentment products has yet to be determined, as well as any minimum specifications upon which recovery may be based.

Conclusion

This report was prepared for the CHEC group by Util-Assist (www.util-assist.com).

Should you have any concerns or questions please do not hesitate to call.

Yours truly,

James Douglas
President

tel: (905) 967-0770 ext 201
email: jdouglas@util-assist.com

CornerstonE
Hydro Electric Concepts

Schedule A1 - LDC Authorization - Centre Wellington Hydro Ltd.

Centre Wellington Hydro Ltd.
730 Gartshore
P.O. Box 217
Fergus, Ontario
N1M 2W8

TOWNSHIP OF CENTRE WELLINGTON
UNITY IS STRENGTH
HYDRO

<u>RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year</u>

Centre Wellington Hydro Ltd. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Centre Wellington Hydro Ltd.
   Doug Sherwood, President/Secretary
   phone: (519) 843-2900
   e-mail: sherwood@cwhydro.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   Yes

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

$0.59 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 6,144 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.59 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Centre Wellington Hydro Ltd.

Dec 12/06
Date

Schedule A2 - LDC Authorization – COLLUS Power Corp.

COLLUS Power Corp.
PO Box 189
43 Stewart Road
Collingwood, Ontario
L9Y 3Z5

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

COLLUS Power Corp. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   COLLUS Power Corp.
   Darius Vaiciunas, Load Mgmt and Regulatory Coordinator
   phone: (705) 445-1800 ext 2227
   e-mail: dvaiciunas@collus.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

$0.26 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 14,124 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.26 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

Once a complete plan and budget has been completed through 2007, a commitment from the regulator regarding the level of cost recovery will be required before the implementation phase is initiated and contracts with suppliers and installers are signed. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
COLLUS Power Corp.

Dec 12/06
Date

Schedule A3 - LDC Authorization - Grand Valley Energy Inc.

Grand Valley Energy Inc.
5 Main St. N., Box 100
Grand Valley, Ontario
L0N 1G0

<u>RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year</u>

Grand Valley Energy Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Grand Valley Energy Inc.
   c/o George Dick, President of Orangeville Hydro
   phone: (519) 942-8000
   e-mail: gdick@orangevillehydro.on.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

$0.30 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2009 – Implement Plan (See Generic Section in Main Document)
2010 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2009 – Implement Plan (See Generic Section in Main Document)
2010 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2009 with a total customer base of 678 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - Collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined.

CornerstonE
Hydro Electric Concepts

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that 100% cost recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Grand Valley Energy Inc.

Dec 12, 06
Date

Schedule A4 - LDC Authorization - Innisfil Hydro

Innisfil Hydro Distribution Systems Limited
2073 Commerce Park Drive
Innisfil, Ontario
L9S 4A2

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Innisfil Hydro Distribution Systems Limited is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Innisfil Hydro Distribution Systems Limited
   Shannon Brown, IT/Settlements Officer
   phone: (705) 431-6870 ext 237
   e-mail: shannonb@innisfilhydro.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is being recovered from your customers?**

$0.28 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan filed (participating member of the Ontario Utilities Smart Metering working group)
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan filed (participating member of the Ontario Utilities Smart Metering working group)
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

CornerstonE
Hydro Electric Concepts

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ’s	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization and operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with an estimated total customer base of 14,000 (not including Unmetered Scattered Loads, Street Lights and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.28 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without assurance of this recovery, there is financial risk associated with finalizing the procurement phase and beginning mass deployment.

Signature
Innisfil Hydro Distribution Systems Limited

12/12/06
Date

Schedule A5 - LDC Authorization - Lakefront Utilities Inc.

Lakefront Utilities Inc.
P.O. Box 577
207 Division St.
Cobourg, Ontario
K9A 4L3

<u>RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year</u>

Lakefront Utilities Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Lakefront Utilities Inc.
   Derek C. Paul, Manager Regulatory Compliance and Finance
   phone: (905) 372-2193
   e-mail: dpaul@lusi.on.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

$0.30 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 8,881 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.30 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

CornerstonE
Hydro Electric Concepts

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout. Since Lakefront also has water services and has historically billed both electricity and water services, our requirements for SM will include the potential future functionality and capability of interrogating water meters.

Signature
Lakefront Utilities Inc.

Dec/11/06
Date

Schedule A6 - LDC Authorization - Lakeland Power Distribution Ltd.

Lakeland Power Distribution Ltd.
5-45 Cairns Crescent
Huntsville, Ontario
P1H 2M2

<u>RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year</u>

Lakeland Power Distribution Ltd. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Lakeland Power Distribution Ltd.
   Chris Litschko, President & CEO
   phone: (705) 789-5442
   e-mail: cjlitschko@lakelandholding.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

   $0.30 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

CornerstonE
Hydro Electric Concepts

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 9,030 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.30 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Lakeland Power Distribution Ltd.

Dec 12, 2006
Date

Schedule A7 - LDC Authorization - Midland Power Utility Corp.

Midland Power Utility Corporation
16984 Hwy 12, PO Box 820
Midland, Ontario
L4R 4P4

MIDLAND POWER UTILITY CORPORATION

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Midland Power Utility Corp. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Midland Power Utility Corporation
   Phil Marley, CMA, President & CEO
   phone: (705) 526-9362 ext 204
   e-mail: pmarley@midlandpuc.on.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

   $0.30 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

CornerstonE
Hydro Electric Concepts

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 6,516 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.30 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

CornerstonE
Hydro Electric Concepts

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout. Additional funding starting in 2007 will ensure MPUC has resources available for deployment.

Signature
Midland Power Utility Corp.

Dec 12/06
Date

Schedule A8 - LDC Authorization - Orangeville Hydro Limited

Orangeville Hydro Limited
400 C Line, Box 400
Orangeville, Ontario
L9W 2Z7

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Orangeville Hydro Limited is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Orangeville Hydro Limited
   George Dick, President
   phone: (519) 942-8000
   e-mail: gdick@orangevillehydro.on.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

   $0.30 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2009 – Implement Plan (See Generic Section in Main Document)
   2010 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2009 – Implement Plan (See Generic Section in Main Document)
   2010 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ’s	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2009 with a total customer base of 9,998 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.30 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that 100% cost recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Orangeville Hydro Limited

Dec 12, 06
Date

Schedule A9 - LDC Authorization - Orillia Power Distribution Corporation

Orillia Power Distribution Corporation
360 West St. S.
P.O. Box 398
Orillia, Ontario
L3V 6J9

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Orillia Power Distribution Corporation is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

    Orillia Power Distribution Corporation
    Pauline Welsh, Regulatory Officer
    phone: (705) 326-2495 ext 240
    e-mail: pwelsh@orilliapower.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

    No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

    N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

   $0.27 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 12,500 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - Collect $0.27 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined.

CornerstonE
Hydro Electric Concepts

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Pauline Welsh
Signature
Orillia Power Distribution Corporation

Dec 12/06
Date

Schedule A10 - LDC Authorization - Parry Sound Power Corp.

Parry Sound Power Corp.
125 William Street
Parry Sound, Ontario
P2A 1V9

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Parry Sound Power Corp. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Parry Sound Power Corp.
   Calvin Epps, President
   phone: (705) 746-5866
   e-mail: calvin@pspower.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

$0.24 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 3,300 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.24 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Parry Sound Power Corp.

Dec 12/06
Date

Schedule A11 - LDC Authorization - Rideau St. Lawrence Distribution Inc.

Rideau St. Lawrence Distribution Inc.
985 Industrial Rd.
P.O. Box 699
Prescott, Ontario
K0E 1T0

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Rideau St. Lawrence Distribution Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Rideau St. Lawrence Distribution Inc.
   John Walsh, President & CEO
   phone: (613) 925-3851
   e-mail: jwalsh@ripnet.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

$0.30 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 5,850 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.30 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

Current funding is appropriate for procurement preparation phase. Funding relief will be required in 2007 rate year due to mass deployment.

Dec 12/06

Signature
Rideau St. Lawrence Distribution Inc.

Date

Schedule A12 - LDC Authorization - Wasaga Distribution Inc.

Wasaga Distribution Inc.
950 River Rd.West
Box 20
Wasaga Beach, Ontario
L9Z 1A2

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Wasaga Distribution Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Wasaga Distribution Inc.
   Paul Trace, Manager, Planning & Technical Services
   phone: (705) 429-2517
   e-mail: p.trace@wasagadist.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

   $0.28 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 10,600 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.28 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Paul T. Loer

Signature
Wasaga Distribution Inc.

Dec 12/06

Date

Schedule A13 - LDC Authorization - Wellington North Power Inc.

Wellington North Power Inc.
290 Queen St. West
Box 359
Mount Forest, Ontario
N0G 2L0

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Wellington North Power Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Wellington North Power Inc.
   Judy Rosebrugh, Administrator/Secretary-Treasurer
   phone: (519) 323-1710
   e-mail: jrosebrugh@wellingtonnorthpower.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   Yes

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   Wellington North Power Inc. is seeking an additional $335,610.00 recovery for Smart Meters, included in Rate Base Adjustments ADJ-1. The corresponding amortization adjustment calculation has been calculated as $13,424.00 in ADJ-3b.

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

Wellington North Power's Decision and Order sets the amount to be recovered at $3.50 per installed meter. Board staff revised our model to recover $0.64 per customer per month for all customer classes with the exception of Street and Sentinel lighting class.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

Our 2006 EDR proposal indicated that WNP was hoping to install one third of our meters every year for three years at an estimated cost of $335,610 per year. Unfortunately the revenue collected annual from the customer will be $25,000 and the Board of Directors for Wellington North Power proposes that is the amount we will spend.

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

Wellington North Power agrees that the current funding may be appropriate for the planning stages of our smart meter implementation plan. However, Wellington North Power Inc. does not believe the current funding for Smart Meters is sufficient for the procurement and deployment. Our utility does not have the funds available to finance the Smart Meters and would hope that the Regulator would correct this in the next rate adjustment.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of 100 percent of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout. Wellington North Power would like some assurance, the meter data repository, data transfer, communications between stakeholders will be ready and tested.

John Schmidt
Signature
Wellington North Power Inc

December 12, 2006
Date

Schedule A14 - LDC Authorization - Westario Power Inc.

Westario Power Inc.
385 Queen Street
Kincardine, Ontario
N2Z 2R4

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Westario Power Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Westario Power Inc.
   Patrick Protomanni, Manager of System Reliability
   phone: (519) 396-3485 ext 231
   e-mail: patrick.protomanni@westario.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

$0.46 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 20,782 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - Collect $0.46 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

We will develop our Smart Meter plan through 2007. A clear, balanced, and fair funding and cost recovery model needs to be in place before deployment. This model will provide us with the support to move to the implementation phase. The risk associated with having no firm model is very great and we are averse to deploying Smart Meters without the cost certainty matter resolved.

Signature
Westario Power Inc.

DEC 12, 2006
Date

Schedule A15 - LDC Authorization - West Coast Huron Energy (Goderich Hydro)

West Coast Huron Energy Inc.
(Goderich Hydro)
64 West St.
Goderich, Ontario
N7A 2K4

<u>RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year</u>

West Coast Huron Energy Inc. (Goderich Hydro) is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   West Coast Huron Energy Inc. (Goderich Hydro)
   Larry J. McCabe, President/Secretary
   phone: (519) 524-8344 or 519-524-7371
   e-mail: lmccabe.goderich.ca

1. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

2. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

3. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

   $0.26 of the monthly service charge per customer is currently being collected except for these rate classes: sentinel lights, street lights and un-metered scattered load.

4. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

5. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

CornerstonE
Hydro Electric Concepts

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	**2007**	**2008**	**2009**	**2010**
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	**2007**	**2008**	**2009**	**2010**
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	**2007**	**2008**	**2009**	**2010**
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

6. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 3,776 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

7. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

8. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - Collect $0.26 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 – to be determined
May 1/08 to Apr. 30/09 – to be determined
May 1/09 to Apr. 30/10 – to be determined
- 2010 and beyond - continue to collect, amount to be determined – until costs are recovered

9. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without assurance of this recovery, there is financial risk associated with finalizing the procurement phase and beginning mass deployment.

Signature
West Coast Huron Energy Inc. (Goderich Hydro)

Dec 12/06
Date

Schedule A16 - LDC Authorization - Woodstock Hydro Services

Woodstock Hydro Services
16 Graham St.
P.O. Box 245
Woodstock, Ontario
N4S 7X4

Woodstock Hydro
An ISO 9001:2000 Registered Company

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Woodstock Hydro Services is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

    Woodstock Hydro Services
    Jay Heaman, Manager of Engineering & Conservation
    phone: (519) 537-7172 ext 255
    e-mail: jheaman@woodstockhydro.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

    No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

    N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much is this being recovered from your customers?**

   The rate being collected for all customers after taking into account excluded street light and scattered load is $0.27.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ’s	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**

- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation qualities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 14,306 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

Existing funding (existing and proposed) is definitely not sufficient to finance the roll-out of a SMIP. We expect total costs and required rates to support the SMIP will be made clearer in the coming weeks.

May 1/06 to Apr. 30/07 - Collect $0.27 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined.

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The City of Woodstock now has over 30% of its residential customer base and a small number of commercial customers participating in the pay-as-you-go metering/billing model. Our plan must include conventional smart metering for the short term, with a longer term plan that will provide the pay-as-you-go option to those who wish to continue participating in this customer choice program. The discontinuation of this metering technology was a topic of concern during the election process for politicians, landlords and electricity customers using, or wishing to use this metering technology. Woodstock has over 18 years of experience with this customer choice and effective CDM technology and it is quickly becoming apparent that our local population expect us to maintain this service going forward. As such, our SMIP plan MUST include pay-as-you-go functionality as a layer on top of the smart metering 24 hour/2 way communication criteria. Smart metering technology is evolving quickly, and we expect this option will be available well in advance of the 2010 saturation deadline.

We understand recovery of the smart metering assets will be provided through rates, however we need to better understand how this cost recovery process will be handled prior to implementation of a plan.

Signature
Woodstock Hydro Services

Dec 12 2006
Date

STRANDED METER RATE RIDER AMOUNTS

Background

On December 15, 2011, the OEB issued Guideline G-2011-0001 “Smart Meter Funding and Cost Recovery – Final Disposition.” This guideline included filing instructions related to the recovery of stranded meter costs associated with Smart Metering activities conducted by electricity distributors. The OEB’s regulations provide that “distributors be held whole with respect to the cost recovery of stranded meters (i.e. conventional meters replaced as part of the Smart Meter initiative).”

In this Application, WPI is requesting to recover its stranded meter costs, in the form of rate riders calculated by rate class, over a two year period, from May 1, 2013 to April 30, 2014.

WPI is specifically requesting the following:

- A rate rider of $0.6744 per metered Residential customer per month and a rate rider of $4.1574 per metered GS<50 customer per month

See Table 2 below for calculations of rate riders.

- The rate rider values have been derived from the residual net book value of those meters that have been stranded as a result of the implementation of the Smart Metering Initiative (“SMI”).

As part of the SMI, WPI began replacing conventional meters with Smart Meters in 2009 for Residential and GS<50 rate class customers. As these meters were replaced, WPI ceased depreciation in its accounting records. The original capital costs and related accumulated amortization were transferred to OEB 1555.

For this disposition, WPI recalculated what depreciation should have been to December 31, 2012. The 2012 depreciation has been calculated on a forecast basis. As shown in

Table 1, the residual net book value of the stranded meters as at December 31, 2012 has been forecasted to be $561,216.

Table 1: Stranded Meter Treatment (Appendix 2-S of Filing Requirements)

Year	Notes	Cumulative Gross Asset Value	Cumulative Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -	$ -	$ -
2007					$ -	$ -	$ -
2008					$ -	$ -	$ -
2009		$ 664,055	$ 246,718	$ 2,657	$ 414,680	$ 5,223	$ 409,457
2010		$ 950,232	$ 401,681	$ 4,409	$ 544,142	$ 6,339	$ 537,803
2011		$ 1,221,695	$ 511,911	$ 4,409	$ 705,375	$ 6,339	$ 699,036
2012	(1)	$ 1,221,695	$ 649,731	$ 4,409	$ 567,555	$ 6,339	$ 561,216

Based on the above, a calculation of a $0.6744 per metered Residential customer per month and a calculation of $4.1574 per metered GS<50 customer per month for the stranded meter rate rider has been completed in Table 2 below. The stranded meter rate rider was derived by first calculating the percentage of actual meter costs for meters removed from service between Residential and GS<50 rate classes based on the net book value at the time the smart meter was installed. Then, taking that percentage and applying it to the total residual net book value of stranded meters as at December 31, 2012 per Table 1 above. Finally, dividing the balance by the projected average number of metered customers for Residential and GS<50 rate classes for January 1, 2013 to December 31, 2013, over the proposed two year recovery period. A two year recovery period was elected so as to calculate a rider that was reasonable within the bill impact models completed in Exhibit 8 of this rate application.

WPI plans to install smart meters for its General Service > 50kW Class in 2012 and as such, seeks approval to record its stranded meters for the class General Service > 50kW in Sub-account Stranded Meter Costs of Account 1555 for disposition in a future proceeding as the net book value of these conventional meters is yet to be determined.

Table 2: Calculation of Stranded Meter Cost Rate Rider

Total for Recovery		**561,216**				
Recovery Period (years)	**2**					
Annual Recovery		**280,608**				
Customer Class	**Net Book Value**	**% share**	**Annual $**	**Customers***	**Rate**	**per month**
Residential	315,965	56.3%	157,982	19,520	**$8.0934**	**$0.6744**
General Service < 50 kW	245,251	43.7%	122,626	2,458	**$49.8884**	**$4.1574**
TOTAL	**561,216**	**100.0%**	**280,608**			

* per load forecast

Disposition

Upon approval of the final rate order, the revenues collected from the separate stranded meter rate riders will be recorded in sub-account 1555 “Sub-account Stranded Meter Costs” to draw down the balance of the net book value of the stranded meters. To date, no interest carrying charges have been calculated on stranded meters. However, WPI will start to calculate interest on the effective date of the rate order, which will be recorded separately in a sub-account.

File Number:	EB2012-0176
Exhibit:	9
Tab:	3
Schedule:	3
Attachment:	1
Page:	1
Date:	Ocotber 9, 2012

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Cumulative Gross Asset Value	Cumulative Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -	$ -	$ -
2007					$ -	$ -	$ -
2008					$ -	$ -	$ -
2009		$ 664,055	$ 246,718	$ 2,657	$ 414,680	$ 5,223	$ 409,457
2010		$ 950,232	$ 401,681	$ 4,409	$ 544,142	$ 6,339	$ 537,803
2011		$ 1,221,695	$ 511,911	$ 4,409	$ 705,375	$ 6,339	$ 699,036
2012	(1)	$ 1,221,695	$ 649,731	$ 4,409	$ 567,555	$ 6,339	$ 561,216

Notes:

(1) *For 2012, please indicate whether the amounts provided are on a forecast or actual basis.*

Some distributors have transferred the cost of stranded meters from Account 1860 - Meters to "Sub-account Stranded Meter Costs of Account 1555", while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen. please provide the information under either of the two scenarios (A and B below), as applicable.

Scenario A: *If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555, the above table should be completed and the following information should be provided.*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, which were transferred to this sub-account as of December 31, 2010.

3 A statement as to whether or not, since transferring the removed stranded meter costs to the sub-account, the recording of depreciation expenses was continued in order to reduce the net book value through accumulated depreciation. If so, the total depreciation expense amount for the period from the time the costs for the stranded meters were transferred to the sub-account to December 31, 2010 should be provided.

If no depreciation expenses were recorded to reduce the net book value of stranded meter costs through accumulated depreciation, the total depreciation expense amount that would have been applicable from the time that the stranded meter costs were transferred to the sub-account of Account 1555 to December 31, 2010 should be provided. In addition, the following information should be provided:

a) Whether or not carrying charges were recorded for the stranded meter cost balances in the sub-account, and if so, the total carrying charges recorded to December 31, 2010.

b) The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when the smart meters will have been fully deployed (e.g., as of December 31, 2010). If the smart meters have been fully deployed, the actual amount should be provided.

c) A description as to how the applicant intends to recover in rates the remaining costs for stranded meters, including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

Scenario B: *If the stranded meter costs remained recorded in Account 1860, the above table should be completed and the following information should be provided:*

1. A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2. The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2010.

3. A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2010.

4. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2010.

5. The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

6. A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

Distributors should also provide the Net Book Value per class of meter as of December 31, 2010 as well as the number of meters that were removed / stranded. In preparing this information, distributors should review the Board's letter of January 16, 2007 *Stranded Meter Costs Related to the Installation of Smart Meters* which stated that records were to be kept of the type and number of each meter to support the stranded meter costs.

Smart Meter Model for Electricity Distributors (2013 Filers)

Version 3.00

Utility Name	Westario Power Inc.
Assigned EB Number	EB-2012-0176
Name and Title	Lisa Milne, CEO
Phone Number	(519) 507-6666 x 216
Email Address	lisa.milne@westario.com
Date	31-Aug-12
Last COS Re-based Year	2009

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Smart Meter Model for Electricity Distributors (2013 Filers)

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data

Smart Meter Installation Plan

	2006	2007	2008	2009	2010	2011	2012	2013	Total
	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential	0	0	0	12,799	5,146	1,575			19520
General Service < 50 kW	0	0	0	872	572	1,014			2458
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)	0	0	0	13671	5718	2589	0	0	21978
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	0.00%	0.00%	0.00%	62.20%	88.22%	100.00%	0.00%	100.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed	0	0	0	0	0	0	80		80
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed	0	0	0	13671	5718	2589	80	0	22058

1 Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	Asset Type	2006	2007	2008	2009	2010	2011	2012	2013	Total
	Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter	0	16,539	17,043	1,711,276	205,200	324,045			$ 2,274,103
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				288,854	305,328	444,849			$ 1,039,031
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Hardware				19,880	41,893	1,100			$ 62,873
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*	Applications Software				43,754	65,463				$ 109,217
Total Advanced Metering Communications Devices (AMCD)		$ -	$ 16,539	$ 17,043	$ 2,063,764	$ 617,884	$ 769,994	$ -	$ -	$ 3,485,224

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	Asset Type	2006	2007	2008	2009	2010	2011	2012	2013	Total
		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.2.1 Collectors	Smart Meter				58,963	0				$ 58,963
1.2.2 Repeaters *(may include radio licence, etc.)*										$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Smart Meter									$ -
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 58,963	$ -	$ -	$ -	$ -	$ 58,963

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.3.1 Computer Hardware										$ -
1.3.2 Computer Software										$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*	Applications Software						100,000	50,000		$ 150,000
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 50,000	$ -	$ 150,000

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.4.1 Activiation Fees										$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*										$ -
1.5.2 AMI Interface to CIS										$ -
1.5.3 Professional Fees										$ -
1.5.4 Integration										$ -
1.5.5 Program Management										$ -
1.5.6 Other AMI Capital										$ -
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Costs Related to Minimum Functionality		$ -	$ 16,539	$ 17,043	$ 2,122,727	$ 617,884	$ 869,994	$ 50,000	$ -	$ 3,694,186

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06										$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service	Smart Meter							260,000		$ 260,000
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.	Applications Software						0	15,000		$ 15,000
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ 275,000	$ -	$ 275,000
Total Smart Meter Capital Costs		$ -	$ 16,539	$ 17,043	$ 2,122,727	$ 617,884	$ 869,994	$ 325,000	$ -	$ 3,969,186

2 OM&A Expenses

	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)									
2.1.1 Maintenance *(may include meter reverification costs, etc.)*				30,131	32,572	2,276	4,538		$ 69,516
2.1.2 Other *(please specifiy)* Operating Costs				2,653	48,756	32,105	41,268		$ 124,783
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ 32,784	$ 81,328	$ 34,381	$ 45,806	$ -	$ 194,299
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)									
2.2.1 Maintenance									$ -
2.2.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)									
2.3.1 Hardware Maintenance *(may include server support, etc.)*									$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*									$ -
2.3.2 Other *(please specifiy)*									$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)									
2.4.1 WAN Maintenance									$ -
2.4.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY									
2.5.1 Business Process Redesign									$ -
2.5.2 Customer Communication (may include project communication, etc.)									$ -
2.5.3 Program Management									$ -
2.5.4 Change Management (may include training, etc.)									$ -
2.5.5 Administration Costs		220	125	27,956	60,824	21,522	55,038		$ 165,686
2.5.6 Other AMI Expenses *(please specify)*									$ -
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ 220	$ 125	$ 27,956	$ 60,824	$ 21,522	$ 55,038	$ -	$ 165,686
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ 220	$ 125	$ 60,741	$ 142,152	$ 55,903	$ 100,844	$ -	$ 359,985

2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual			
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06									$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service									$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.									$ -
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs	$ -	$ 220	$ 125	$ 60,741	$ 142,152	$ 55,903	$ 100,844	$ -	$ 359,985

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**									
3.1.1	Smart Meter	$ -	$ 16,539	$ 17,043	$ 2,059,093	$ 510,528	$ 768,894	$ 260,000	$ -	$ 3,632,096
3.1.2	Computer Hardware	$ -	$ -	$ -	$ 19,880	$ 41,893	$ 1,100	$ -	$ -	$ 62,873
3.1.3	Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ 43,754	$ 65,463	$ 100,000	$ 65,000	$ -	$ 274,217
3.1.7	**Total Capital Costs**	**$ -**	**$ 16,539**	**$ 17,043**	**$ 2,122,727**	**$ 617,884**	**$ 869,994**	**$ 325,000**	**$ -**	**$ 3,969,186**
3.2	**OM&A Costs**									
3.2.1	**Total OM&A Costs**	**$ -**	**$ 220**	**$ 125**	**$ 60,741**	**$ 142,152**	**$ 55,903**	**$ 100,844**	**$ -**	**$ 359,985**

Smart Meter Model for Electricity Distributors (2013 Filers)

	2006	2007	2008	2009	2010	2011	2012	2013
Cost of Capital								
Capital Structure[1]								
Deemed Short-term Debt Capitalization			4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization		0.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	100.0%	100.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Preferred Shares								
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters								
Deemed Short-term Debt Rate			1.33%	1.33%	1.33%	1.33%	1.33%	2.08%
Long-term Debt Rate (actual/embedded/deemed)[2]	5.80%	5.80%	5.82%	5.82%	5.82%	5.82%	5.82%	4.41%
Target Return on Equity (ROE)	9.0%	9.00%	8.01%	8.01%	8.01%	8.01%	8.01%	9.12%
Return on Preferred Shares								
WACC	9.00%	9.00%	6.52%	6.52%	6.52%	6.52%	6.52%	6.20%
Working Capital Allowance								
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	13.0%
(% of the sum of Cost of Power + controllable expenses)								
Taxes/PILs								
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%	0.00%

Depreciation Rates

(expressed as expected useful life in years)

Smart Meters - years	15	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years								
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other Equipment - years								
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

CCA Rates

Smart Meters - CCA Class	8	8	8	8	8	8	8	8
Smart Meters - CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
Computer Equipment - CCA Class		50	50	52	52	50	50	50
Computer Equipment - CCA Rate		55%	55%	100%	100%	55%	55%	55%
General Equipment - CCA Class	8	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class	12	12	12	12	12	12	12	12
Applications Software - CCA Rate	100%	100%	100%	100%	100%	100%	100%	100%

Assumptions

[1] *Planned smart meter installations occur evenly throughout the year.*

[2] *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Smart Meter Model for Electricity Distributors (2013 Filers)

	2006	2007	2008	2009	2010	2011	2012	2013
Net Fixed Assets - Smart Meters								
Gross Book Value								
Opening Balance		$ -	$ 16,539	$ 33,582	$ 2,092,675	$ 2,603,203	$ 3,369,141	$ 3,626,141
Capital Additions during year (from Smart Meter Costs)	$ -	$ 16,539	$ 17,043	$ 2,059,093	$ 510,528	$ 768,894	$ 260,000	$ -
Retirements/Removals (if applicable)						$ 2,955	$ 3,000	
Closing Balance	$ -	$ 16,539	$ 33,582	$ 2,092,675	$ 2,603,203	$ 3,369,141	$ 3,626,141	$ 3,626,141
Accumulated Depreciation								
Opening Balance		$ -	-$ 551	-$ 2,222	-$ 73,097	-$ 229,626	-$ 428,803	-$ 662,079
Amortization expense during year	$ -	-$ 551	-$ 1,671	-$ 70,875	-$ 156,529	-$ 199,177	-$ 233,276	-$ 241,743
Retirements/Removals (if applicable)								
Closing Balance	$ -	-$ 551	-$ 2,222	-$ 73,097	-$ 229,626	-$ 428,803	-$ 662,079	-$ 903,822
Net Book Value								
Opening Balance	$ -	$ -	$ 15,988	$ 31,360	$ 2,019,578	$ 2,373,576	$ 2,940,338	$ 2,964,062
Closing Balance	$ -	$ 15,988	$ 31,360	$ 2,019,578	$ 2,373,576	$ 2,940,338	$ 2,964,062	$ 2,722,320
Average Net Book Value	$ -	$ 7,994	$ 23,674	$ 1,025,469	$ 2,196,577	$ 2,656,957	$ 2,952,200	$ 2,843,191
Net Fixed Assets - Computer Hardware								
Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ 19,880	$ 61,773	$ 62,873	$ 62,873
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 19,880	$ 41,893	$ 1,100	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ 19,880	$ 61,773	$ 62,873	$ 62,873	$ 62,873
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	-$ 1,988	-$ 10,153	-$ 22,618	-$ 35,193
Amortization expense during year	$ -	$ -	$ -	-$ 1,988	-$ 8,165	-$ 12,465	-$ 12,575	-$ 12,575
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	-$ 1,988	-$ 10,153	-$ 22,618	-$ 35,193	-$ 47,767
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ 17,892	$ 51,620	$ 40,255	$ 27,681
Closing Balance	$ -	$ -	$ -	$ 17,892	$ 51,620	$ 40,255	$ 27,681	$ 15,106
Average Net Book Value	$ -	$ -	$ -	$ 8,946	$ 34,756	$ 45,938	$ 33,968	$ 21,393

Net Fixed Assets - Computer Software (including Applications Software)								
Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ 43,754	$ 109,217	$ 209,217	$ 274,217
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 43,754	$ 65,463	$ 100,000	$ 65,000	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ 43,754	$ 109,217	$ 209,217	$ 274,217	$ 274,217
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	-$ 4,375	-$ 19,672	-$ 51,516	-$ 99,859
Amortization expense during year	$ -	$ -	$ -	-$ 4,375	-$ 15,297	-$ 31,843	-$ 48,343	-$ 54,843
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	-$ 4,375	-$ 19,672	-$ 51,516	-$ 99,859	-$ 154,702
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ 39,379	$ 89,544	$ 157,701	$ 174,358
Closing Balance	$ -	$ -	$ -	$ 39,379	$ 89,544	$ 157,701	$ 174,358	$ 119,514
Average Net Book Value	$ -	$ -	$ -	$ 19,689	$ 64,461	$ 123,622	$ 166,029	$ 146,936
Net Fixed Assets - Tools and Equipment								
Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Fixed Assets - Other Equipment								
Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Smart Meter Model for Electricity Distributors (2013 Filers)

	2006	2007	2008	2009	2010	2011	2012	2013
Average Net Fixed Asset Values (from Sheet 4)								
Smart Meters	$ -	$ 7,994	$ 23,674	$ 1,025,469	$ 2,196,577	$ 2,656,957	$ 2,952,200	$ 2,843,191
Computer Hardware	$ -	$ -	$ -	$ 8,946	$ 34,756	$ 45,938	$ 33,968	$ 21,393
Computer Software	$ -	$ -	$ -	$ 19,689	$ 64,461	$ 123,622	$ 166,029	$ 146,936
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ -**	**$ 7,994**	**$ 23,674**	**$ 1,054,104**	**$ 2,295,794**	**$ 2,826,517**	**$ 3,152,197**	**$ 3,011,520**
Working Capital								
Operating Expenses (from Sheet 2)	$ -	$ 220	$ 125	$ 60,741	$ 142,152	$ 55,903	$ 100,844	$ -
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%	13%
Working Capital Allowance	$ -	$ 33	$ 19	$ 9,111	$ 21,323	$ 8,385	$ 15,127	$ -
Incremental Smart Meter Rate Base	**$ -**	**$ 8,027**	**$ 23,693**	**$ 1,063,215**	**$ 2,317,117**	**$ 2,834,903**	**$ 3,167,324**	**$ 3,011,520**
Return on Rate Base								
Capital Structure								
Deemed Short Term Debt	$ -	$ -	$ 948	$ 42,529	$ 92,685	$ 113,396	$ 126,693	$ 120,461
Deemed Long Term Debt	$ -	$ -	$ 13,268	$ 595,401	$ 1,297,586	$ 1,587,546	$ 1,773,701	$ 1,686,451
Equity	$ -	$ 8,027	$ 9,477	$ 425,286	$ 926,847	$ 1,133,961	$ 1,266,930	$ 1,204,608
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ 8,027	$ 23,693	$ 1,063,215	$ 2,317,117	$ 2,834,903	$ 3,167,324	$ 3,011,520
Return on								
Deemed Short Term Debt	$ -	$ -	$ 13	$ 566	$ 1,233	$ 1,508	$ 1,685	$ 2,506
Deemed Long Term Debt	$ -	$ -	$ 772	$ 34,652	$ 75,519	$ 92,395	$ 103,229	$ 74,372
Equity	$ -	$ 722	$ 759	$ 34,065	$ 74,240	$ 90,830	$ 101,481	$ 109,860
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ 722	$ 1,544	$ 69,283	$ 150,993	$ 184,734	$ 206,396	$ 186,738
Operating Expenses	$ -	$ 220	$ 125	$ 60,741	$ 142,152	$ 55,903	$ 100,844	$ -
Amortization Expenses (from Sheet 4)								
Smart Meters	$ -	$ 551	$ 1,671	$ 70,875	$ 156,529	$ 199,177	$ 233,276	$ 241,743
Computer Hardware	$ -	$ -	$ -	$ 1,988	$ 8,165	$ 12,465	$ 12,575	$ 12,575
Computer Software	$ -	$ -	$ -	$ 4,375	$ 15,297	$ 31,843	$ 48,343	$ 54,843
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ -	$ 551	$ 1,671	$ 77,239	$ 179,992	$ 243,485	$ 294,194	$ 309,161
Incremental Revenue Requirement before Taxes/PILs	$ -	$ 1,494	$ 3,340	$ 207,263	$ 473,136	$ 484,121	$ 601,434	$ 495,899
Calculation of Taxable Income								
Incremental Operating Expenses	$ -	$ 220	$ 125	$ 60,741	$ 142,152	$ 55,903	$ 100,844	$ -
Amortization Expense	$ -	$ 551	$ 1,671	$ 77,239	$ 179,992	$ 243,485	$ 294,194	$ 309,161
Interest Expense	$ -	$ -	$ 785	$ 35,218	$ 76,752	$ 93,903	$ 104,914	$ 76,878
Net Income for Taxes/PILs	$ -	$ 722	$ 759	$ 34,065	$ 74,240	$ 90,830	$ 101,481	$ 109,860
Grossed-up Taxes/PILs (from Sheet 7)	$ -	-$ 179.00	-$ 1,063.66	-$ 60,278.77	-$ 113,717.84	-$ 90,171.99	-$ 60,637.40	-$ 8,331.44
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ 1,315	$ 2,276	$ 146,984	$ 359,419	$ 393,949	$ 540,796	$ 487,568

Smart Meter Model for Electricity Distributors (2013 Filers)

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ 14,885.10	$ 27,246.78	$ 1,874,981.04	$ 1,959,459.74	$ 2,259,572.31	$ 2,041,657.85
Capital Additions	$ -	$ 16,539.00	$ 17,043.00	$ 2,059,092.91	$ 510,527.67	$ 768,893.91	$ 260,000.00	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ 16,539.00	$ 31,928.10	$ 2,086,339.69	$ 2,385,508.71	$ 2,728,353.65	$ 2,519,572.31	$ 2,041,657.85
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 8,269.50	$ 8,521.50	$ 1,029,546.46	$ 255,263.84	$ 384,446.96	$ 130,000.00	$ -
Reduced UCC	$ -	$ 8,269.50	$ 23,406.60	$ 1,056,793.24	$ 2,130,244.88	$ 2,343,906.69	$ 2,389,572.31	$ 2,041,657.85
CCA Rate Class	8	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ 1,653.90	$ 4,681.32	$ 211,358.65	$ 426,048.98	$ 468,781.34	$ 477,914.46	$ 408,331.57
Closing UCC	$ -	$ 14,885.10	$ 27,246.78	$ 1,874,981.04	$ 1,959,459.74	$ 2,259,572.31	$ 2,041,657.85	$ 1,633,326.28

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 9,940.00	$ 20,946.71	$ 10,223.48	$ 4,600.57
Capital Additions Computer Hardware	$ -	$ -	$ -	$ 19,880.00	$ 41,893.42	$ 1,099.95	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ 19,880.00	$ 51,833.42	$ 22,046.66	$ 10,223.48	$ 4,600.57
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 9,940.00	$ 20,946.71	$ 549.98	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ 9,940.00	$ 30,886.71	$ 21,496.69	$ 10,223.48	$ 4,600.57
CCA Rate Class	0	50	50	52	52	50	50	50
CCA Rate	0%	55%	55%	100%	100%	55%	55%	55%
CCA	$ -	$ -	$ -	$ 9,940.00	$ 30,886.71	$ 11,823.18	$ 5,622.92	$ 2,530.31
Closing UCC	$ -	$ -	$ -	$ 9,940.00	$ 20,946.71	$ 10,223.48	$ 4,600.57	$ 2,070.26

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	8	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC - Applications Software

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 21,877.00	$ 32,731.30	$ 50,000.00	$ 32,500.00
Capital Additions Applications Software	$ -	$ -	$ -	$ 43,754.00	$ 65,462.60	$ 100,000.00	$ 65,000.00	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ 43,754.00	$ 87,339.60	$ 132,731.30	$ 115,000.00	$ 32,500.00
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 21,877.00	$ 32,731.30	$ 50,000.00	$ 32,500.00	$ -
Reduced UCC	$ -	$ -	$ -	$ 21,877.00	$ 54,608.30	$ 82,731.30	$ 82,500.00	$ 32,500.00
CCA Rate Class	12	12	12	12	12	12	12	12
CCA Rate	100%	100%	100%	100%	100%	100%	100%	100%
CCA	$ -	$ -	$ -	$ 21,877.00	$ 54,608.30	$ 82,731.30	$ 82,500.00	$ 32,500.00
Closing UCC	$ -	$ -	$ -	$ 21,877.00	$ 32,731.30	$ 50,000.00	$ 32,500.00	$ -

Smart Meter Model for Electricity Distributors (2013 Filers)

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
INCOME TAX								
Net Income	$ -	$ 722.42	$ 759.11	$ 34,065.42	$ 74,240.43	$ 90,830.29	$ 101,481.06	$ 109,860.25
Amortization	$ -	$ 551.30	$ 1,670.70	$ 77,238.63	$ 179,991.65	$ 243,484.63	$ 294,194.09	$ 309,160.76
CCA - Smart Meters	$ -	-$ 1,653.90	-$ 4,681.32	-$ 211,358.65	-$ 426,048.98	-$ 468,781.34	-$ 477,914.46	-$ 408,331.57
CCA - Computers	$ -	$ -	$ -	-$ 9,940.00	-$ 30,886.71	-$ 11,823.18	-$ 5,622.92	-$ 2,530.31
CCA - Applications Software	$ -	$ -	$ -	-$ 21,877.00	-$ 54,608.30	-$ 82,731.30	-$ 82,500.00	-$ 32,500.00
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ -	-$ 380.18	-$ 2,251.51	-$ 131,871.60	-$ 257,311.90	-$ 229,020.89	-$ 170,362.22	-$ 24,340.87
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Income Taxes Payable	$ -	-$ 137.32	-$ 754.26	-$ 43,517.63	-$ 79,766.69	-$ 64,698.40	-$ 44,720.08	-$ 6,206.92
ONTARIO CAPITAL TAX								
Smart Meters	$ -	$ 15,987.70	$ 31,360.00	$ 2,019,577.68	$ 2,373,576.10	$ 2,940,338.37	$ 2,964,062.28	$ 2,722,319.51
Computer Hardware	$ -	$ -	$ -	$ 17,892.00	$ 51,620.08	$ 40,255.35	$ 27,680.68	$ 15,106.00
Computer Software (Including Application Software)	$ -	$ -	$ -	$ 39,378.60	$ 89,544.14	$ 157,700.82	$ 174,357.50	$ 119,514.18
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ -	$ 15,987.70	$ 31,360.00	$ 2,076,848.28	$ 2,514,740.32	$ 3,138,294.54	$ 3,166,100.45	$ 2,856,939.69
Less: Exemption								
Deemed Taxable Capital	$ -	$ 15,987.70	$ 31,360.00	$ 2,076,848.28	$ 2,514,740.32	$ 3,138,294.54	$ 3,166,100.45	$ 2,856,939.69
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ 35.97	$ 70.56	$ 4,672.91	$ 1,886.06	$ -	$ -	$ -
Change in Income Taxes Payable	$ -	-$ 137.32	-$ 754.26	-$ 43,517.63	-$ 79,766.69	-$ 64,698.40	-$ 44,720.08	-$ 6,206.92
Change in OCT	$ -	$ 35.97	$ 70.56	$ 4,672.91	$ 1,886.06	$ -	$ -	$ -
PILs	$ -	-$ 101.35	-$ 683.70	-$ 38,844.72	-$ 77,880.63	-$ 64,698.40	-$ 44,720.08	-$ 6,206.92
Gross Up PILs								
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Change in Income Taxes Payable	$ -	-$ 214.97	-$ 1,134.22	-$ 64,951.68	-$ 115,603.90	-$ 90,171.99	-$ 60,637.40	-$ 8,331.44
Change in OCT	$ -	$ 35.97	$ 70.56	$ 4,672.91	$ 1,886.06	$ -	$ -	$ -
PILs	$ -	-$ 179.00	-$ 1,063.66	-$ 60,278.77	-$ 113,717.84	-$ 90,171.99	-$ 60,637.40	-$ 8,331.44

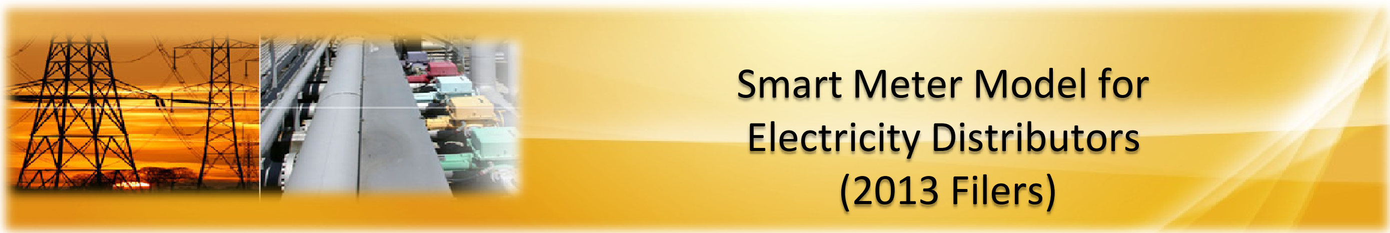
Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the funding adder revenues.

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	3.92%
2012 Q1	1.47%	3.92%
2012 Q2	1.47%	3.51%
2012 Q3	1.47%	3.51%
2012 Q4	1.47%	3.51%
2013 Q1	1.47%	3.51%
2013 Q2	1.47%	3.51%
2013 Q3		

Account 1555 - Sub-account Funding Adder Revenues

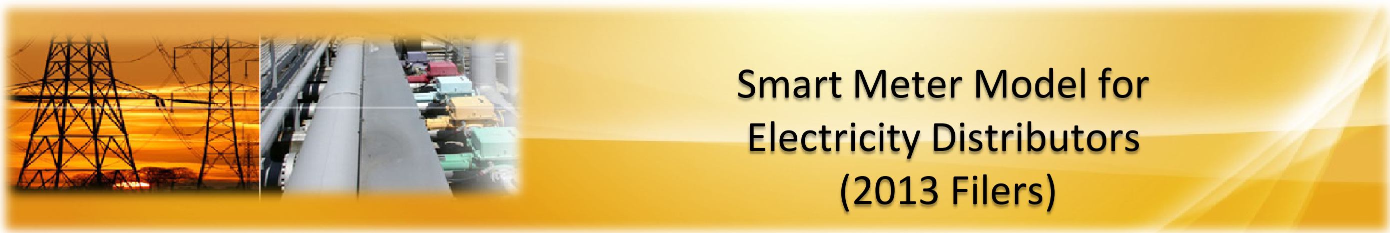
Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
Jan-06	*2006*	*Q1*	$ -		0.00%	$ -	$ -		
Feb-06	*2006*	*Q1*	$ -		0.00%	$ -	$ -		
Mar-06	*2006*	*Q1*	$ -		0.00%	$ -	$ -		
Apr-06	*2006*	*Q2*	$ -		4.14%	$ -	$ -		
May-06	*2006*	*Q2*	$ -		4.14%	$ -	$ -		
Jun-06	*2006*	*Q2*	$ -		4.14%	$ -	$ -		
Jul-06	*2006*	*Q3*	$ -	$ 3,254.16	4.59%	$ -	$ 3,254.16		
Aug-06	*2006*	*Q3*	$ 3,254.16	$ 9,915.75	4.59%	$ 12.45	$ 13,182.36		
Sep-06	*2006*	*Q3*	$ 13,169.91	$ 11,619.84	4.59%	$ 50.37	$ 24,840.12		
Oct-06	*2006*	*Q4*	$ 24,789.75	$ 9,132.88	4.59%	$ 94.82	$ 34,017.45		
Nov-06	*2006*	*Q4*	$ 33,922.63	$ 9,505.46	4.59%	$ 129.75	$ 43,557.84		
Dec-06	*2006*	*Q4*	$ 43,428.09	$ 9,130.36	4.59%	$ 166.11	$ 52,724.56	$ 53,011.95	
Jan-07	*2007*	*Q1*	$ 52,558.45	$ 9,732.96	4.59%	$ 201.04	$ 62,492.45		
Feb-07	*2007*	*Q1*	$ 62,291.41	$ 10,165.23	4.59%	$ 238.26	$ 72,694.90		
Mar-07	*2007*	*Q1*	$ 72,456.64	$ 11,053.97	4.59%	$ 277.15	$ 83,787.76		
Apr-07	*2007*	*Q2*	$ 83,510.61	$ 8,301.14	4.59%	$ 319.43	$ 92,131.18		
May-07	*2007*	*Q2*	$ 91,811.75	$ 8,151.75	4.59%	$ 351.18	$ 100,314.68		
Jun-07	*2007*	*Q2*	$ 99,963.50	$ 6,568.90	4.59%	$ 382.36	$ 106,914.76		
Jul-07	*2007*	*Q3*	$ 106,532.40	$ 5,552.18	4.59%	$ 407.49	$ 112,492.07		
Aug-07	*2007*	*Q3*	$ 112,084.58	$ 6,493.55	4.59%	$ 428.72	$ 119,006.85		
Sep-07	*2007*	*Q3*	$ 118,578.13	$ 4,544.59	4.59%	$ 453.56	$ 123,576.28		
Oct-07	*2007*	*Q4*	$ 123,122.72	$ 5,468.43	5.14%	$ 527.38	$ 129,118.53		
Nov-07	*2007*	*Q4*	$ 128,591.15	$ 5,680.56	5.14%	$ 550.80	$ 134,822.51		
Dec-07	*2007*	*Q4*	$ 134,271.71	$ 5,336.63	5.14%	$ 575.13	$ 140,183.47	$ 91,762.39	
Jan-08	*2008*	*Q1*	$ 139,608.34	$ 5,496.54	5.14%	$ 597.99	$ 145,702.87		
Feb-08	*2008*	*Q1*	$ 145,104.88	$ 5,737.23	5.14%	$ 621.53	$ 151,463.64		
Mar-08	*2008*	*Q1*	$ 150,842.11	$ 5,551.70	5.14%	$ 646.11	$ 157,039.92		
Apr-08	*2008*	*Q2*	$ 156,393.81	$ 5,411.63	4.08%	$ 531.74	$ 162,337.18		
May-08	*2008*	*Q2*	$ 161,805.44	$ 5,472.47	4.08%	$ 550.14	$ 167,828.05		
Jun-08	*2008*	*Q2*	$ 167,277.91	$ 5,457.82	4.08%	$ 568.74	$ 173,304.47		
Jul-08	*2008*	*Q3*	$ 172,735.73	$ 5,508.81	3.35%	$ 482.22	$ 178,726.76		



This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

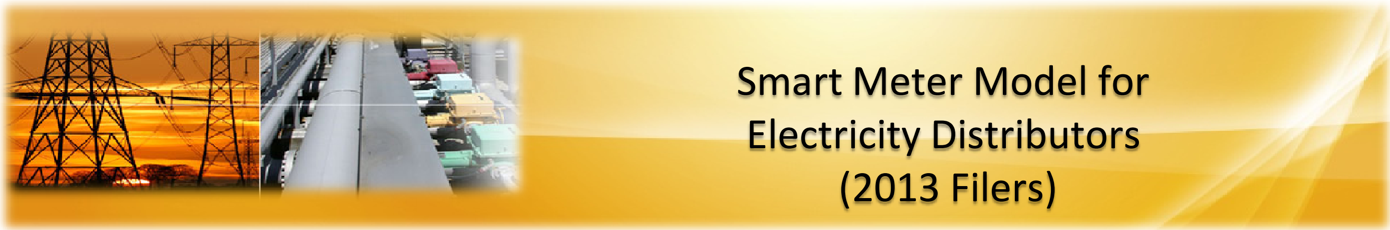
Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
2013 Q4			Aug-08	2008	Q3	$ 178,244.54	$ 5,727.36	3.35%	$ 497.60	$ 184,469.50		
			Sep-08	2008	Q3	$ 183,971.90	$ 5,562.75	3.35%	$ 513.59	$ 190,048.24		
			Oct-08	2008	Q4	$ 189,534.65	$ 5,659.89	3.35%	$ 529.12	$ 195,723.66		
			Nov-08	2008	Q4	$ 195,194.54	$ 5,409.06	3.35%	$ 544.92	$ 201,148.52		
			Dec-08	2008	Q4	$ 200,603.60	$ 5,663.33	3.35%	$ 560.02	$ 206,826.95	$ 73,302.31	
			Jan-09	2009	Q1	$ 206,266.93	$ 5,731.92	2.45%	$ 421.13	$ 212,419.98		
			Feb-09	2009	Q1	$ 211,998.85	$ 5,825.68	2.45%	$ 432.83	$ 218,257.36		
			Mar-09	2009	Q1	$ 217,824.53	$ 5,533.98	2.45%	$ 444.73	$ 223,803.24		
			Apr-09	2009	Q2	$ 223,358.51	$ 5,509.85	1.00%	$ 186.13	$ 229,054.49		
			May-09	2009	Q2	$ 228,868.36	$ 5,601.82	1.00%	$ 190.72	$ 234,660.90		
			Jun-09	2009	Q2	$ 234,470.18	$ 31,562.23	1.00%	$ 195.39	$ 266,227.80		
			Jul-09	2009	Q3	$ 266,032.41	$ 18,363.33	0.55%	$ 121.93	$ 284,517.67		
			Aug-09	2009	Q3	$ 284,395.74	$ 21,927.81	0.55%	$ 130.35	$ 306,453.90		
			Sep-09	2009	Q3	$ 306,323.55	$ 21,335.61	0.55%	$ 140.40	$ 327,799.56		
			Oct-09	2009	Q4	$ 327,659.16	$ 22,178.98	0.55%	$ 150.18	$ 349,988.32		
			Nov-09	2009	Q4	$ 349,838.14	$ 21,481.62	0.55%	$ 160.34	$ 371,480.10		
			Dec-09	2009	Q4	$ 371,319.76	$ 31,370.06	0.55%	$ 170.19	$ 402,860.01	$ 199,167.21	
			Jan-10	2010	Q1	$ 402,689.82	$ 25,024.06	0.55%	$ 184.57	$ 427,898.45		
			Feb-10	2010	Q1	$ 427,713.88	$ 17,213.35	0.55%	$ 196.04	$ 445,123.27		
			Mar-10	2010	Q1	$ 444,927.23	$ 22,206.98	0.55%	$ 203.92	$ 467,338.13		
			Apr-10	2010	Q2	$ 467,134.21	$ 21,451.94	0.55%	$ 214.10	$ 488,800.25		
			May-10	2010	Q2	$ 488,586.15	$ 22,297.27	0.55%	$ 223.94	$ 511,107.36		
			Jun-10	2010	Q2	$ 510,883.42	$ 21,587.08	0.55%	$ 234.15	$ 532,704.65		
			Jul-10	2010	Q3	$ 532,470.50	$ 22,272.91	0.89%	$ 394.92	$ 555,138.33		
			Aug-10	2010	Q3	$ 554,743.41	$ 22,304.85	0.89%	$ 411.43	$ 577,459.69		
			Sep-10	2010	Q3	$ 577,048.26	$ 21,616.91	0.89%	$ 427.98	$ 599,093.15		
			Oct-10	2010	Q4	$ 598,665.17	$ 22,356.94	1.20%	$ 598.67	$ 621,620.78		
			Nov-10	2010	Q4	$ 621,022.11	$ 21,640.06	1.20%	$ 621.02	$ 643,283.19		
			Dec-10	2010	Q4	$ 642,662.17	$ 22,407.60	1.20%	$ 642.66	$ 665,712.43	$ 266,733.35	
			Jan-11	2011	Q1	$ 665,069.77	$ 22,440.21	1.47%	$ 814.71	$ 688,324.69		
			Feb-11	2011	Q1	$ 687,509.98	$ 20,302.78	1.47%	$ 842.20	$ 708,654.96		
			Mar-11	2011	Q1	$ 707,812.76	$ 22,422.16	1.47%	$ 867.07	$ 731,101.99		



This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
			Apr-11	*2011*	*Q2*	$ 730,234.92	$ 21,857.95	1.47%	$ 894.54	$ 752,987.41		
			May-11	*2011*	*Q2*	$ 752,092.87	$ 22,437.67	1.47%	$ 921.31	$ 775,451.85		
			Jun-11	*2011*	*Q2*	$ 774,530.54	$ 21,819.79	1.47%	$ 948.80	$ 797,299.13		
			Jul-11	*2011*	*Q3*	$ 796,350.33	$ 22,533.71	1.47%	$ 975.53	$ 819,859.57		
			Aug-11	*2011*	*Q3*	$ 818,884.04	$ 22,588.59	1.47%	$ 1,003.13	$ 842,475.76		
			Sep-11	*2011*	*Q3*	$ 841,472.63	$ 21,993.68	1.47%	$ 1,030.80	$ 864,497.11		
			Oct-11	*2011*	*Q4*	$ 863,466.31	$ 22,616.90	1.47%	$ 1,057.75	$ 887,140.96		
			Nov-11	*2011*	*Q4*	$ 886,083.21	$ 21,833.06	1.47%	$ 1,085.45	$ 909,001.72		
			Dec-11	*2011*	*Q4*	$ 907,916.27	$ 22,596.02	1.47%	$ 1,112.20	$ 931,624.49	$ 276,996.01	
			Jan-12	*2012*	*Q1*	$ 930,512.29	$ 22,698.40	1.47%	$ 1,139.88	$ 954,350.57		
			Feb-12	*2012*	*Q1*	$ 953,210.69	$ 21,151.97	1.47%	$ 1,167.68	$ 975,530.34		
			Mar-12	*2012*	*Q1*	$ 974,362.66	$ 23,207.78	1.47%	$ 1,193.59	$ 998,764.03		
			Apr-12	*2012*	*Q2*	$ 997,570.44	$ 22,317.51	1.47%	$ 1,222.02	$ 1,021,109.97		
			May-12	*2012*	*Q2*	$ 1,019,887.95	$ 22,500.00	1.47%	$ 1,249.36	$ 1,043,637.31		
			Jun-12	*2012*	*Q2*	$ 1,042,387.95	$ -	1.47%	$ 1,276.93	$ 1,043,664.88		
			Jul-12	*2012*	*Q3*	$ 1,042,387.95	$ -	1.47%	$ 1,276.93	$ 1,043,664.88		
			Aug-12	*2012*	*Q3*	$ 1,042,387.95	$ -	1.47%	$ 1,276.93	$ 1,043,664.88		
			Sep-12	*2012*	*Q3*	$ 1,042,387.95	$ -	1.47%	$ 1,276.93	$ 1,043,664.88		
			Oct-12	*2012*	*Q4*	$ 1,042,387.95	$ -	1.47%	$ 1,276.93	$ 1,043,664.88		
			Nov-12	*2012*	*Q4*	$ 1,042,387.95	$ -	1.47%	$ 1,276.93	$ 1,043,664.88		
			Dec-12	*2012*	*Q4*	$ 1,042,387.95	$ -	1.47%	$ 1,276.93	$ 1,043,664.88	$ 126,786.70	
			Jan-13	*2013*	*Q1*	$ 1,042,387.95		1.47%	$ 1,276.93	$ 1,043,664.88		
			Feb-13	*2013*	*Q1*	$ 1,042,387.95		1.47%	$ 1,276.93	$ 1,043,664.88		
			Mar-13	*2013*	*Q1*	$ 1,042,387.95		1.47%	$ 1,276.93	$ 1,043,664.88		
			Apr-13	*2013*	*Q2*	$ 1,042,387.95		1.47%	$ 1,276.93	$ 1,043,664.88		
			May-13	*2013*	*Q2*	$ 1,042,387.95			$ -	$ 1,042,387.95		
			Jun-13	*2013*	*Q2*	$ 1,042,387.95			$ -	$ 1,042,387.95		
			Jul-13	*2013*	*Q3*	$ 1,042,387.95		0.00%	$ -	$ 1,042,387.95		
			Aug-13	*2013*	*Q3*	$ 1,042,387.95		0.00%	$ -	$ 1,042,387.95		
			Sep-13	*2013*	*Q3*	$ 1,042,387.95		0.00%	$ -	$ 1,042,387.95		
			Oct-13	*2013*	*Q4*	$ 1,042,387.95		0.00%	$ -	$ 1,042,387.95		
			Nov-13	*2013*	*Q4*	$ 1,042,387.95		0.00%	$ -	$ 1,042,387.95		



This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
			Dec-13	*2013*	*Q4*	$ 1,042,387.95		0.00%	$ -	$ 1,042,387.95	$ 5,107.72	
			Total Funding Adder Revenues Collected				**$ 1,042,387.95**		**$ 45,371.97**	**$ 1,087,759.92**	**$ 1,087,759.92**	

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

	Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%	
2006 Q2	4.14%	4.68%	
2006 Q3	4.59%	5.05%	
2006 Q4	4.59%	4.72%	
2007 Q1	4.59%	4.72%	
2007 Q2	4.59%	4.72%	
2007 Q3	4.59%	5.18%	
2007 Q4	5.14%	5.18%	
2008 Q1	5.14%	5.18%	
2008 Q2	4.08%	5.18%	
2008 Q3	3.35%	5.43%	
2008 Q4	3.35%	5.43%	
2009 Q1	2.45%	6.61%	
2009 Q2	1.00%	6.61%	
2009 Q3	0.55%	5.67%	
2009 Q4	0.55%	4.66%	
2010 Q1	0.55%	4.34%	
2010 Q2	0.55%	4.34%	
2010 Q3	0.89%	4.66%	
2010 Q4	1.20%	4.01%	
2011 Q1	1.47%	4.29%	
2011 Q2	1.47%	4.29%	
2011 Q3	1.47%	4.29%	
2011 Q4	1.47%	3.92%	
2012 Q1	1.47%	3.92%	
2012 Q2	1.47%	3.51%	
2012 Q3	1.47%	3.51%	
2012 Q4	1.47%	3.51%	
2013 Q1	1.47%	3.51%	
2013 Q2	1.47%	3.51%	
2013 Q3	0.00%	0.00%	
2013 Q4	0.00%	0.00%	

Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	2006	Q1	$ -			-	0.00%	-	-
Feb-06	2006	Q1	-			-	0.00%	-	-
Mar-06	2006	Q1	-			-	0.00%	-	-
Apr-06	2006	Q2	-			-	4.14%	-	-
May-06	2006	Q2	-			-	4.14%	-	-
Jun-06	2006	Q2	-			-	4.14%	-	-
Jul-06	2006	Q3	-			-	4.59%	-	-
Aug-06	2006	Q3	-			-	4.59%	-	-
Sep-06	2006	Q3	-			-	4.59%	-	-
Oct-06	2006	Q4	-			-	4.59%	-	-
Nov-06	2006	Q4	-			-	4.59%	-	-
Dec-06	2006	Q4	-			-	4.59%	-	-
Jan-07	2007	Q1	-			-	4.59%	-	-
Feb-07	2007	Q1	-			-	4.59%	-	-
Mar-07	2007	Q1	-			-	4.59%	-	-
Apr-07	2007	Q2	-			-	4.59%	-	-
May-07	2007	Q2	-			-	4.59%	-	-
Jun-07	2007	Q2	-			-	4.59%	-	-
Jul-07	2007	Q3	-			-	4.59%	-	-
Aug-07	2007	Q3	-			-	4.59%	-	-
Sep-07	2007	Q3	-			-	4.59%	-	-
Oct-07	2007	Q4	-	$ 89.30		89.30	5.14%	-	-
Nov-07	2007	Q4	89.30	$ 656.39		745.69	5.14%	0.38	0.38
Dec-07	2007	Q4	745.69			745.69	5.14%	3.19	3.58
Jan-08	2008	Q1	745.69			745.69	5.14%	3.19	6.77
Feb-08	2008	Q1	745.69			745.69	5.14%	3.19	9.96
Mar-08	2008	Q1	745.69	$ 100.40		846.09	5.14%	3.19	13.16
Apr-08	2008	Q2	846.09	$ 104.00		950.09	4.08%	2.88	16.04
May-08	2008	Q2	950.09	$ 125.30		1,075.39	4.08%	3.23	19.27
Jun-08	2008	Q2	1,075.39	$ 402.50		1,477.89	4.08%	3.66	22.92
Jul-08	2008	Q3	1,477.89	$ 381.29		1,859.18	3.35%	4.13	27.05
Aug-08	2008	Q3	1,859.18	$ 418.01		2,277.19	3.35%	5.19	32.24
Sep-08	2008	Q3	2,277.19	$ 303.30		2,580.49	3.35%	6.36	38.60
Oct-08	2008	Q4	2,580.49	$ 770.70		3,351.19	3.35%	7.20	45.80
Nov-08	2008	Q4	3,351.19	$ 2,881.14		6,232.33	3.35%	9.36	55.15

Dec-08	2008	Q4	6,232.33	$ 265.30		6,497.63	3.35%	17.40	72.55
Jan-09	2009	Q1	6,497.63		$ 405.07	6,902.70	2.45%	13.27	85.82
Feb-09	2009	Q1	6,902.70		$ 188.48	7,091.18	2.45%	14.09	99.91
Mar-09	2009	Q1	7,091.18	$ 24,142.20	$ 175.63	31,409.01	2.45%	14.48	114.39
Apr-09	2009	Q2	31,409.01		$ 175.63	31,584.64	1.00%	26.17	140.56
May-09	2009	Q2	31,584.64	$ 190.17	$ 437.66	32,212.47	1.00%	26.32	166.88
Jun-09	2009	Q2	32,212.47	$ 477.60	$ 3,624.84	36,314.91	1.00%	26.84	193.73
Jul-09	2009	Q3	36,314.91	$ 6,762.12	$ 8,266.22	51,343.25	0.55%	16.64	210.37
Aug-09	2009	Q3	51,343.25	$ 4,576.49	$ 4,366.43	60,286.17	0.55%	23.53	233.90
Sep-09	2009	Q3	60,286.17	$ 2,604.85	$ 8,568.23	71,459.25	0.55%	27.63	261.54
Oct-09	2009	Q4	71,459.25	$ 8,447.89	$ 14,350.49	94,257.63	0.55%	32.75	294.29
Nov-09	2009	Q4	94,257.63	$ 2,235.35	$ 14,590.11	111,083.09	0.55%	43.20	337.49
Dec-09	2009	Q4	111,083.09	$ 11,304.33	$ 18,053.21	140,440.63	0.55%	50.91	388.40
Jan-10	2010	Q1	140,440.63	$ 4,184.00		144,624.63	0.55%	64.37	452.77
Feb-10	2010	Q1	144,624.63	$ 17,166.00		161,790.63	0.55%	66.29	519.06
Mar-10	2010	Q1	161,790.63	$ 140,364.00	$ 37,990.00	340,144.63	0.55%	74.15	593.21
Apr-10	2010	Q2	340,144.63	$ 32,885.08	$ 12,705.00	385,734.71	0.55%	155.90	749.11
May-10	2010	Q2	385,734.71	$ 15,776.99	$ 12,830.26	414,341.96	0.55%	176.80	925.91
Jun-10	2010	Q2	414,341.96	-$ 155,897.12	$ 19,568.92	278,013.76	0.55%	189.91	1,115.81
Jul-10	2010	Q3	278,013.76	$ 1,379.38	$ 14,121.00	293,514.14	0.89%	206.19	1,322.01
Aug-10	2010	Q3	293,514.14	$ 12,224.32	$ 14,005.50	319,743.96	0.89%	217.69	1,539.70
Sep-10	2010	Q3	319,743.96	$ 5,222.52	$ 13,445.08	338,411.56	0.89%	237.14	1,776.84
Oct-10	2010	Q4	338,411.56	$ 6,011.77	$ 17,852.49	362,275.82	1.20%	338.41	2,115.25
Nov-10	2010	Q4	362,275.82	$ 12,454.97	$ 14,262.80	388,993.59	1.20%	362.28	2,477.53
Dec-10	2010	Q4	388,993.59	$ 50,380.09	$ 17,373.76	456,747.44	1.20%	388.99	2,866.52
Jan-11	2011	Q1	456,747.44	$ 3,207.43	$ 17,616.25	477,571.12	1.47%	559.52	3,426.04
Feb-11	2011	Q1	477,571.12	$ 7,739.33	$ 17,627.38	502,937.83	1.47%	585.02	4,011.06
Mar-11	2011	Q1	502,937.83	$ 14,792.73	$ 17,937.00	535,667.56	1.47%	616.10	4,627.16
Apr-11	2011	Q2	535,667.56	$ 9,659.66	$ 20,633.74	565,960.96	1.47%	656.19	5,283.35
May-11	2011	Q2	565,960.96	$ 9,628.36	$ 18,458.06	594,047.38	1.47%	693.30	5,976.65
Jun-11	2011	Q2	594,047.38	$ 9,740.27	$ 18,507.16	622,294.81	1.47%	727.71	6,704.36
Jul-11	2011	Q3	622,294.81	$ 9,103.92	$ 18,965.17	650,363.90	1.47%	762.31	7,466.67
Aug-11	2011	Q3	650,363.90	$ 7,383.36	$ 20,499.10	678,246.36	1.47%	796.70	8,263.37
Sep-11	2011	Q3	678,246.36	$ 9,748.99	$ 20,467.49	708,462.84	1.47%	830.85	9,094.22
Oct-11	2011	Q4	708,462.84	$ 10,265.93	$ 21,757.19	740,485.96	1.47%	867.87	9,962.09
Nov-11	2011	Q4	740,485.96	$ 5,602.00	$ 20,648.25	766,736.21	1.47%	907.10	10,869.18
Dec-11	2011	Q4	766,736.21	-$ 43,519.23	$ 24,100.19	747,317.17	1.47%	939.25	11,808.44
Jan-12	2012	Q1	747,317.17	$ 11,250.08	$ 22,753.93	781,321.18	1.47%	915.46	12,723.90
Feb-12	2012	Q1	781,321.18	$ 11,523.73	$ 22,815.67	815,660.58	1.47%	957.12	13,681.02
Mar-12	2012	Q1	815,660.58	$ -	$ 22,785.30	838,445.88	1.47%	999.18	14,680.20
Apr-12	2012	Q2	838,445.88	$ 40,147.08	$ 24,356.81	902,949.77	1.47%	1,027.10	15,707.30
May-12	2012	Q2	902,949.77	$ 11,000.00	$ 23,000.00	936,949.77	1.47%	1,106.11	16,813.41
Jun-12	2012	Q2	936,949.77	$ 11,000.00	$ 23,000.00	970,949.77	1.47%	1,147.76	17,961.17
Jul-12	2012	Q3	970,949.77	$ 11,000.00	$ 23,000.00	1,004,949.77	1.47%	1,189.41	19,150.59
Aug-12	2012	Q3	1,004,949.77	$ 11,000.00	$ 23,000.00	1,038,949.77	1.47%	1,231.06	20,381.65
Sep-12	2012	Q3	1,038,949.77	$ 11,000.00	$ 23,000.00	1,072,949.77	1.47%	1,272.71	21,654.37
Oct-12	2012	Q4	1,072,949.77	$ 11,000.00	$ 23,000.00	1,106,949.77	1.47%	1,314.36	22,968.73
Nov-12	2012	Q4	1,106,949.77	$ 11,000.00	$ 23,000.00	1,140,949.77	1.47%	1,356.01	24,324.74
Dec-12	2012	Q4	1,140,949.77	$ 11,000.00	$ 23,000.00	1,174,949.77	1.47%	1,397.66	25,722.41
Jan-13	2013	Q1	1,174,949.77			1,174,949.77	1.47%	1,439.31	27,161.72
Feb-13	2013	Q1	1,174,949.77			1,174,949.77	1.47%	1,439.31	28,601.03
Mar-13	2013	Q1	1,174,949.77			1,174,949.77	1.47%	1,439.31	30,040.35
Apr-13	2013	Q2	1,174,949.77			1,174,949.77	1.47%	1,439.31	31,479.66
May-13	2013	Q2	1,174,949.77			1,174,949.77	0.00%	-	31,479.66
Jun-13	2013	Q2	1,174,949.77			1,174,949.77	0.00%	-	31,479.66
Jul-13	2013	Q3	1,174,949.77			1,174,949.77	0.00%	-	31,479.66
Aug-13	2013	Q3	1,174,949.77			1,174,949.77	0.00%	-	31,479.66
Sep-13	2013	Q3	1,174,949.77			1,174,949.77	0.00%	-	31,479.66
Oct-13	2013	Q4	1,174,949.77			1,174,949.77	0.00%	-	31,479.66
Nov-13	2013	Q4	1,174,949.77			1,174,949.77	0.00%	-	31,479.66
Dec-13	2013	Q4	1,174,949.77			1,174,949.77	0.00%	-	31,479.66

$	413,664.27	$	761,285.50	$	1,174,949.77

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ -	$ -	$ -	$ -	4.37%	$ -
2007	$ 220.00	$ 551.30	$ 771.30	$ 385.65	4.73%	$ 18.23
2008	$ 125.00	$ 1,670.70	$ 2,567.00	$ 1,669.15	3.98%	$ 66.43
2009	$ 60,740.74	$ 77,238.63	$ 140,546.37	$ 71,556.69	1.14%	$ 813.96
2010	$ 142,152.08	$ 179,991.65	$ 462,690.10	$ 301,618.24	0.80%	$ 2,405.41
2011	$ 55,902.82	$ 243,484.63	$ 762,077.56	$ 612,383.83	1.47%	$ 9,002.04
2012	$ 100,844.00	$ 294,194.09	$ 1,157,115.65	$ 959,596.60	1.47%	$ 14,106.07
2013	$ -	$ 309,160.76	$ 1,466,276.41	$ 1,311,696.03	0.49%	$ 6,427.31
Cumulative Interest to 2011						$ 12,306.07
Cumulative Interest to 2012						$ 26,412.14
Cumulative Interest to 2013						$ 32,839.45

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012	2013	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ 1,314.72	$ 2,275.95	$ 146,983.95	$ 359,418.51	$ 393,949.07	$ 540,796.20	$ 487,567.66	$ 1,444,738.40
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ 3.58	$ 68.98	$ 315.85	$ 2,478.12	$ 8,941.91	$ 13,913.97		$ 25,722.41
X Sheet 8A (Interest calculated on monthly balances)	$ -	$ 3.58	$ 68.98	$ 315.85	$ 2,478.12	$ 8,941.91	$ 13,913.97	$ 5,757.25	$ 25,722.41
Sheet 8B (Interest calculated on average annual balances)									
SMFA Revenues (from Sheet 8)	$ 52,558.45	$ 87,049.89	$ 66,658.59	$ 196,422.89	$ 262,379.95	$ 265,442.52	$ 111,875.66	$ -	$ 1,042,387.95
SMFA Interest (from Sheet 8)	$ 453.50	$ 4,712.50	$ 6,643.72	$ 2,744.32	$ 4,353.40	$ 11,553.49	$ 14,911.04	$ 5,107.72	$ 50,479.69
Net Deferred Revenue Requirement	-$ 53,011.95	-$ 90,444.09	-$ 70,957.39	-$ 51,867.41	$ 95,163.28	$ 125,894.98	$ 427,923.47	$ 482,459.94	$ 377,593.17

Number of Metered Customers (average for 2013 test year) → 22218

- Number of metered customers for which smart meter were deployed as part of program). Residential and GS < 50 kW customer classes and any other metered classes involved (e.g. GS 50 to 4999 kW for which interval meters were upgraded to utilize AMI and ODS assets)

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding			4
Deferred Incremental Revenue Requirement from 2006 to December 31, 2012 plus Interest on OM&A and Amortization		$	1,470,460.81
SMFA Revenues collected from 2006 to 2013 test year (inclusive) Plus Simple Interest on SMFA Revenues		$	1,092,867.64
Net Deferred Revenue Requirement		$	377,593.17
SMDR	May 1, 2012 to December 31, 2015	$	0.35
Check: Forecasted SMDR Revenues		$	373,262.40
Check: Forecasted SMIRR Revenues		$	487,907.28

Match

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the class-specific SMDRs according to accepted practice. A distributor may choose to use its own methodology, but should provide analogous support for its allocation and derivation of class-specific SMDRs and SMIRRs.

Class-specific SMDRs

Revenue Requirement for Historical Years	2006	2007	2008	2009	2010	2011	2012	Total 2006 to 2012	**Explanation / Allocator**	Residential	GS < 50 kW	GS 50 to 4999 kW	Other (please specify)	Total
									Check Row if SMDR/SMIRR apply to class	X	X	X		3
										%	%	%	%	
									Weighted Meter Cost - Capital	77.00%	14.00%	9.00%		100%
Return on Capital	$ -	$ 722.42	$ 1,543.90	$ 69,283.36	$ 150,992.62	$ 184,733.61	$ 206,395.51	$ 613,671.42	Allocated per class	$ 472,526.99	$ 85,914.00	$ 55,230.43	$ -	
Depreciation/Amortization expense and related interest	$ -	$ 551.30	$ 1,670.70	$ 77,238.63	$ 179,991.65	$ 243,484.63	$ 294,194.09							
	$ -	$ 2.56	$ 64.17	$ 176.81	$ 1,384.60	$ 7,272.24	$ 10,362.06		Weighted Meter Cost - Capital	77%	14%	9%	0%	100%
	$ -	$ 553.86	$ 1,734.87	$ 77,415.44	$ 181,376.25	$ 250,756.88	$ 304,556.15	$ 816,393.45	Allocated per class	$ 628,622.96	$ 114,295.08	$ 73,475.41	$ -	
Operating Expenses and related interest	$ -	$ 220.00	$ 125.00	$ 60,740.74	$ 142,152.08	$ 55,902.82	$ 100,844.00		Number of Smart Meters installed by Class	#	#	#	#	
	$ -	$ 3.58	$ 4.80	$ 139.04	$ 1,093.52	$ 1,669.67	$ 3,551.91			19,520	2,458	240		
	$ -	$ 223.58	$ 129.80	$ 60,879.78	$ 143,245.60	$ 57,572.49	$ 104,395.91	$ 366,447.16	Allocated per class	$ 321,948.35	$ 40,540.42	3958.381407	0	
Revenue Requirement before Taxes/PILs								$ 1,796,512.03		$ 1,423,098.30	$ 240,749.50	$ 132,664.22	$ -	$ -
									Revenue Requirement before PILs	79.21%	13.40%	7.38%	0.00%	100%
Grossed-up Taxes/PILs	$ -	-$ 179.00	-$ 1,063.66	-$ 60,278.77	-$ 113,717.84	-$ 90,171.99	-$ 60,637.40	-$ 326,048.66		-$ 258,277.87	-$ 43,693.59	-$ 24,077.21	$ -	
Total Revenue Requirement plus interest on OM&A and depreciation expense								$ 1,470,463.37		$ 1,164,820.43	$ 197,055.92	$ 108,587.01	$ -	
									Percentage of costs allocated to each clas	79.21%	13.40%	7.38%	0.00%	
								$ 2.56	Percentage of costs for classes with SMDR/SMIRR	79.21%	13.40%	7.38%	0.00%	
										79.21%	13.40%	7.38%	0.00%	
										%	%	%	%	
									SMFA Revenues directly attributable to class	80.00%	13.00%	7.00%		100%
										80.00%	13.00%	7.00%	0.00%	100.00%
									Residual SMFA Revenues (from other metered classes) attributed evenly	0.00%	0.00%	0.00%	0.00%	
									Total	80.00%	13.00%	7.00%	0.00%	
SMFA Revenues plus interest expense								$ 1,092,867.64		$ 874,294.11	$ 142,072.79	$ 76,500.73	$ -	
Net Deferred Revenue Requirement to be recovered via SMDR								$ 377,595.73		$ 290,526.32	$ 54,983.12	$ 32,086.28	$ -	
Average number of metered customers by class (2013)								Average number of customers (2013)		19520	2458	240	0	
Number of Years for SMDR recovery								3.67	years	3.67	3.67	3.67	3.67	
Smart Meter Disposition Rider ($/month per metered customer in the customer class)										$ 0.34	$ 0.51	3.04		
Estimated SMDR Revenues								$ 379,623.92		$ 292,284.67	$ 55,207.66	$ 32,131.58	$ -	

Exhibit 9: Deferral And Variance Accounts

Tab 4 (of 4): LRAM Variance Account ("LRAMVA")

LRAM VARIANCE ACCOUNT STATUS

At this time, the applicant is not including amounts in the LRAM Variance Account (LRAMVA); however, WPI may request for recovery of future amounts in this account in a future application. This is consistent with the information disclosed in the "Ontario Energy Board Accounting Procedures Handbook Frequently Asked Questions" dated July 2012.