November 6, 2013

Ontario Energy Board P.O.
Box 2319 27th Floor
2300 Yonge Street Toronto,
Ontario M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary
Regarding: EB-2013-0139-2014 Cost of Service Application

Dear Ms. Walli,

Please find Hydro Hawkesbury Inc.'s responses to Board Staff and VECC's interrogatories. The following models and attachments are being filed in conjunction with these responses.

- EB-2013-0139 - OPA Final Annual report 2012
- EB-2013-0139 - Worksheet of impact on Revenue Requirement
- EB-2013-0139 EDDVAR_Continuity_Schedule_CoS_v2 2 Nov 6 2013
- EB-2013-0139 HHI 2014 Chapter 2 Appendices Nov 6 2013
- EB-2013-0139 HHI 2014 COS Cost Allocation Model V3 Nov 6 2013
- EB-2013-0139 HHI 2014 COS PILs Workform Nov 6 2013
- EB-2013-0139 HHI 2014 COS RRWF revised Nov 6 2013
- EB-2013-0139 HHI 2014 RTSR MODEL_V4 0_Nov 6 2013
- EB-2013-0139 Responses to IRs Nov 6 2013
- Verified Annual 2012 CDM Report_Hydro Hawkesbury Inc

We would be pleased to provide any further information or details that you may require relative to this application.

Yours truly,

Michel Poulin, General Manager
Hydro Hawkesbury Inc.
850 Tupper Street
Hawkesbury, ON
K6A 3S7

Responses to Board Staff and VECC Interrogatories
2014 Electricity Distribution Rates
Hydro Hawkesbury Inc. ("HHI")
EB-2013-0139
Novembre 6, 2013

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1.0-Staff-1

Ref: Exhibit 1/ Tab 2/ Schedule 3 – Budget Directives and Assumptions

On page 24 of the above reference, HHI states:

> The proposed OM&A cost expenditures for the 2014 Test year are the result of a business planning and work prioritization process that ensures that the most appropriate cost effective solutions are put in place.

a) Please provide more detail of HHI's prioritization process: i.e. who is involved and how is the process carried out?

HHI Response: HHI uses the incremental budgeting approach: The current year's budget becomes the basis for the next year's spending plan. HHI also uses the priority-driven budgeting method for the maintenance of its lines with the main objective of giving the greatest value to the community.

The manager and assistant manager/CFO evaluate each individual expenditure, and through a collaborative process, rank them in order of significance and priority.

Capital projects are a significant part of HHI's budget process. Major expenditures are prioritized in the same manner as any ongoing capital projects.

HHI's capital plan includes all the potential capital projects, such as, capital improvements, capital equipment purchases, engineering studies, comprehensive plan, software upgrades, etc.

HHI's also makes plans for emergency and contingency planning in the event those emergency situations or critical needs occur.

Please provide the type of decision criteria or strategy used to determine which solutions are the most cost effective for HHI and its customers.

HHI Response: HHI's main focus is to keep its rates at the lowest while keeping its distribution system safe and reliable. The utility's rate history validates this as HHI has maintained one the lowest rates in the province of Ontario for the whole of its existence. HHI is one of the most efficiently run utilities in Ontario and that operation and maintenance expenditures are done on a preventative or on a need basis only.

HHI follows the steps identified below when putting together its budget:

1. We identify our priorities
2. Rank our priorities and describe them. When necessary priorities are detailed by engineering studies and analysis.
3. Obtain multiple quotes to obtain and determine the most cost effective option and availability of service.
4. Prepare budget for evaluation by our Board of Directors
5. Evaluate and discuss our budget plan with our Board Members to maintain an efficient and reliable system while keeping costs at the minimum.
6. The Board of Directors question and study the documents that support our proposals.
7. The Board of Directors adopt the proposed budget.

1.0-Staff-2

Ref: Exhibit 1/ Tab 2/ Schedule 7 – Revenue Requirement Work Form

a) Based on the responses to the interrogatories from all parties, please submit a Microsoft Excel file containing an updated RRWF (version 3.00) that represents any changes the applicant wishes to make to the amounts in the previous version of the RRWF. Column E of Sheet 3 should remain unchanged. Adjustments or changed numbers should be input into the applicable cells on columns I or M.

   HHI Response: A revised RRWF model is being filed in conjunction with these replies

b) Please provide a list of all changes made to HHI's original application (by exhibit), including an updated derivation of its revenue requirement, PILs calculation, base rates, rate adders/riders, and bill impacts.

HHI Response: A list of changes to the revenue requirement is being filed in conjunction with these revisions.

1.0 – VECC – 1

Reference: Exhibit 2, Tab 3 (E2.T3.S1)

a) Please provide the causes of interruptions by the following categories (see sample table below or use similar categories which HHI tracks).

HHI Response: A table showing the causes of interruption is presented at the next page.

2009 SYSTEM & SERVICE RELIABILITY INDICES INCLUDING CODE 2 (LOSS OF SUPPLY)

2009 SYSTEM & SERVICES RELIABILITY INDICES INCLUDING CODE # 2	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(4) (SAIDI) (1)/(3)	(5) (SAIFI) (2)/(3)	(4)/(5) (CAIDI)
JAN	74.00	84	5397	0.013711321	0.015564202	0.880952381
FEB	597.08	1195	5404	0.110489144	0.221132494	0.499651325
MAR	3685.75	1271	5408	0.681536612	0.235022189	2.899881983
APR	452.87	1905	5418	0.083585579	0.351605759	0.237725284
MAY	0.00	0	5425	0	0	0
JUN	6058.75	1155	5432	1.115381075	0.212628866	5.245670996
JUL	1001.50	5183	5438	0.184166973	0.95310776	0.19322786
AUG	2033.67	1196	5451	0.000009	0.219409283	0.0000410192
SEPT	327.50	3843	5469	0.059882977	0.702687877	0.08521988
OCT	8.33	10	5473	0.001522626	0.001827151	0.833333333
NOV	0.00	0	5473	0	0	0
DEC	1041.45	947	5475	0.190219178	0.172968037	1.099736008
	15280.9	16789	5439	2.809720669	3.087017146	0.910173328

CODE	Description	2009 Totals Customers affected	2009 Totals Customers Hours
1	Scheduled	2248	1161.92
2	Supply Loss	11102	7465
3	Tree Contact	12	24.00
4	Lightning	29	106.67
5	Def. Equip.	43	30.62
6	Weather	2086	2948.53
7	Adverse Environment	0	0
8	Human Element	1	1.00
9	Animals, Vehicle	107	78.33
0	Unknown	1161	3465.33
	Total	16789	15280.9

2009 SYSTEM & SERVICE RELIABILITY INDICES EXCLUDING CODE 2 (LOOS OF SUPPLY)

2009 SYSTEM & SERVICES RELIABILITY INDICES EXCLUDING CODE #2	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(4) (SAIDI) (1)/(3)	(5) (SAIFI) (2)/(3)	(4)/(5) (CAIDI)
JAN	74	84	5397	0.013711321	0.015564202	0.880952381
FEB	20.08333333	41	5404	0.003716383	0.007586973	0.489837398
MAR	3685.75	1271	5408	0.681536612	0.235022189	2.899881983
APR	260.5333333	751	5418	0.048086625	0.138612034	0.346915224
MAY	0	0	5425	0	0	0
JUN	0.25	1	5432	0.00005	0.000184094	0.25
JUL	683.1666667	1363	5438	0.125628295	0.250643619	0.501222793
AUG	2033.666667	1196	5451	0.373081392	0.219409283	1.70039019
SEPT	9.166666667	23	5469	0.001676114	0.004205522	0.398550725
OCT	8.333333333	10	5473	0.001522626	0.001827151	0.833333333
NOV	0	0	5473	0	0	0
DEC	1041.45	947	5475	0.190219178	0.172968037	1.099736008
	7816.4	5687	5439	1.43721	1.0457	1.37443

CODE	Description	2009 Totals Customers affected	2009 Totals Customers Hours
1	Scheduled	2248	1161.92
2	Supply Loss		
3	Tree Contact	12	24.00
4	Lightning	29	106.67
5	Def. Equip.	43	30.62
6	Weather	2086	2948.53
7	Adverse Environment	0	0
8	Human Element	1	1.00
9	Animals, Vehicle	107	78.33
0	Unknown	1161	3465.33
	Total	5687	7816.4

2010 SYSTEM & SERVICE RELIABILITY INDICES INCLUDING CODE 2 (LOSS OF SUPPLY)

2010 SYSTEM & SERVICE RELIABILITY INDICES INCLUDING CODE 2	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(4) (SAIDI) (1)/(3)	(5) (SAIFI) (2)/(3)	(4)/(5) (CAIDI)
JAN	0.00	0	5478	0	0	0
FEB	4.12	15	5478	0.000751491	0.002738226	0.274444444
MAR	200.72	42	5479	0.036633814	0.007665632	4.778968254
APR	47.67	5	5484	0.008691952	0.000911743	9.533333333
MAY	57.93	62	5483	0.010565384	0.011307678	0.934354839
JUN	668.50	1344	5485	0.121877849	0.245031905	0.497395833
JUL	3339.00	1876	5492	0.607975237	0.341587764	1.779850746
AUG	0.50	1	5499	9.09256E-05	0.000181851	0.5
SEPT	0.00	0	5508	0	0	0
OCT	3250.50	1603	5516	0.589285714	0.290609137	2.027760449
NOV	0.00	0	5520	0	0	0
DEC	766.00	780	5523	0.138692739	0.141227594	0.982051282
	8334.93	5728	5495	1.51670574	1.042323148	1.455120461

CODE	Description	2010 Totals Customers affected	2010 Totals Customers Hours
1	Scheduled	2752	4777.00
2	Supply Loss	759	1898
3	Tree Contact	0	0.00
4	Lightning	0	0.00
5	Def. Equip.	2091	1425.17
6	Weather		
7	Adverse Environment		
8	Human Element	1	0.62
9	Animals, Vehicle	125	234.65
0	Unknown		
	Total	5728	8334.93

2010 SYSTEM & SERVICE RELIABILITY INDICES EXCLUDING CODE 2 (LOOS OF SUPPLY)

2010 SYSTEM & SERVICES RELIABILITY INDICES EXCLUDING CODE #2	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(4) (SAIDI) (1)/(3)	(5) (SAIFI) (2)/(3)	(4)/(5) (CAIDI)
JAN	0	0	5478	0	0	0
FEB	4.116666667	15	5478	0.000751491	0.002738226	0.274444444
MAR	200.7166667	42	5479	0.036633814	0.007665632	4.778968254
APR	47.66666667	5	5484	0.008691952	0.000911743	9.533333333
MAY	57.93	62	5483	0.010565384	0.011307678	0.934354839
JUN	668.5	1344	5485	0.121877849	0.245031905	0.497395833
JUL	3339	1876	5492	0.607975237	0.341587764	1.779850746
AUG	0.5	1	5499	9.09256E-05	0.000181851	0.5
SEPT	0	0	5508	0	0	0
OCT	1353	844	5516	0.245286439	0.153009427	1.603080569
NOV	0	0	5520	0	0	0
DEC	766	780	5523	0.138692739	0.141227594	0.982051282
	6437.43	4969	5495	1.17142	0.9042	1.29552

CODE	Description	2010 Totals Customers affected	2010 Totals Customers Hours
1	Scheduled	2752	4777.00
2	Supply Loss		
3	Tree Contact	0	0.00
4	Lightning	0	0.00
5	Def. Equip.	2091	1425.17
6	Weather	0	0.00
7	Adverse Environment	0	0
8	Human Element	1	0.62
9	Animals, Vehicle	125	234.65
0	Unknown	0	0.00
	Total	4969	6437.43

2011 SYSTEM & SERVICE RELIABILITY INDICES INCLUDING CODE 2 (LOSS OF SUPPLY)

2011 SYSTEM & SERVICE RELIABILITY INDICES INCLUDING CODE 2 (LOSS OF SUPPLY)	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(4) (SAIDI) (1)/(3)	(5) (SAIFI) (2)/(3)	(4)/(5) (CAIDI)
JAN	4867.62	2670	5526	0.88085716	0.483170467	1.823077403
FEB	1064.70	4125	5527	0.19263615	0.746336168	0.258109091
MAR	0.00	0	5528	0	0	0
APR	1.62	1	5529	0.000292398	0.000180865	1.616666667
MAY	0.00	0	5529	0	0	0
JUN	310.42	109	5529	0.056143365	0.019714234	2.847859327
JUL	895.87	1492	5533	0.161913368	0.269654798	0.600446828
AUG	1.63	2	5536	0.000295039	0.000361272	0.816666667
SEPT	412.95	4142	5536	0.074593569	0.748193642	0.099698213
OCT	389.73	628	5539	0.070361678	0.113377866	0.62059448
NOV	9.33	19	5543	0.001683805	0.003427747	0.49122807
DEC	28.80	36	5544	0.005194805	0.006493506	0.8
	7982.67	13224	5533	1.442672329	2.389915511	0.603649929

CODE	Description	2011 Totals Customers affected	2011 Totals Customers Hours
1	Scheduled	646	392.03
2	Supply Loss	12173	6946
3	Tree Contact	0	0.00
4	Lightning	84	300.00
5	Def. Equip.	115	137.88
6	Weather	95	117.87
7	Adverse Environment	0	0
8	Human Element	0	0.00
9	Animals, Vehicle	111	88.75
0	Unknown	0	0.00
	Total	13224	7982.67

2011 SYSTEM & SERVICE RELIABILITY INDICES EXCLUDING CODE 2 (LOOS OF SUPPLY)

2011 SYSTEM & SERVICE RELIABILITY INDICES EXCLUDING CODE 2	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(4) (SAIDI) (1)/(3)	(5) (SAIFI) (2)/(3)	(4)/(5) (CAIDI)
JAN	16.76666667	12	5526	0.003034142	0.002171553	1.397222222
FEB	41.45	32	5527	0.007499548	0.005789759	1.2953125
MAR	0	0	5528	0	0	0
APR	1.616666667	1	5529	0.000292398	0.000180865	1.616666667
MAY	0	0	5529	0	0	0
JUN	310.4166667	109	5529	0.056143365	0.019714234	2.847859327
JUL	164.9166667	163	5533	0.029806012	0.029459606	1.011758691
AUG	1.633333333	2	5536	0.000295039	0.000361272	0.816666667
SEPT	71.86666667	49	5536	0.012981696	0.008851156	1.466666667
OCT	389.7333333	628	5539	0.070361678	0.113377866	0.62059448
NOV	9.333333333	19	5543	0.001683805	0.003427747	0.49122807
DEC	28.8	36	5544	0.005194805	0.006493506	0.8
	1036.533333	1051	5533	0.18733	0.1899	0.98624

CODE	Description	2011 Totals Customers affected	2011 Totals Customers Hours
1	Scheduled	646	392.03
2	Supply Loss	0	0
3	Tree Contact	0	0.00
4	Lightning	84	300.00
5	Def. Equip.	115	137.88
6	Weather	95	117.87
7	Adverse Environment	0	0
8	Human Element	0	0.00
9	Animals, Vehicle	111	88.75
0	Unknown	0	0.00
	Total	1051	1036.53

2012 SYSTEM & SERVICE RELIABILITY INDICES INCLUDING CODE 2 (LOSS OF SUPPLY)

2012 SYSTEM & SERVICE RELIABILITY INDICES INCLUDING CODE # 2	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(SAIDI) (1)/(3)	(2)/(3) (SAIFI)	(4)/(5) (CAIDI)
JAN	122.55	130	5548	0.022089041	0.023431867	0.942692308
FEB	4.27	10	5550	0.000768769	0.001801802	0.426666667
MAR	1761.82	1896	5550	0.317444444	0.341621622	0.9292282
APR	0.00	0	5557	0	0	0
MAY	12.17	17	5558	0.002189037	0.003058654	0.715686275
JUN	103.12	552	5566	0.018526171	0.099173554	0.186805556
JUL	2167.00	1715	5566	0.389328063	0.308120733	1.263556851
AUG	19.97	27	5574	0.003582107	0.004843918	0.739506173
SEPT	6.72	13	5574	0.001204999	0.002332257	0.516666667
OCT	130.63	589	5589	0.023373293	0.105385579	0.221788342
NOV	0.00	0	5596	0	0	0
DEC	0.00	0	5606	0	0	0
	4328.23	4949	5570	0.7771314	0.88858964	0.874567253

CODE	Description	2012 Totals Customers affected	2012 Totals Customers Hours
1	Scheduled	1462	608.75
2	Supply Loss	1088	109
3	Tree Contact	0	0.00
4	Lightning	0	0.00
5	Def. Equip.	49	40.35
6	Weather	1672	3218.77
7	Adverse Environment	8	2.67
8	Human Element	0	0.00
9	Animals, Vehicle	670	348.90
0	Unknown	0	0.00
	Total	4949	4328.233333

2012 SYSTEM & SERVICE RELIABILITY INDICES EXCLUDING CODE 2 (LOOS OF SUPPLY)

2012 SYSTEM AND SERVICE RELIABILITY INDICES EXCLUDING CODE #2	(1) TOTAL CUSTOMER-HOURS OF INTERRUPTIONS	(2) TOTAL CUSTOMER INTERRUPTIONS	(3) TOTAL # OF CUSTOMERS SERVED	(SAIDI) (1)/(3)	(2)/(3) (SAIFI)	(4)/(5) (CAIDI)
JAN	122.55	130	5548	0.022089041	0.023431867	0.942692308
FEB	4.266666667	10	5550	0.000768769	0.001801802	0.426666667
MAR	1761.816667	1896	5550	0.317444444	0.341621622	0.9292282
APR	0	0	5557	0	0	0
MAY	12.16666667	17	5558	0.002189037	0.003058654	0.715686275
JUN	12.45	8	5566	0.002236795	0.001437298	1.55625
JUL	2167	1715	5566	0.389328063	0.308120733	1.263556851
AUG	19.96666667	27	5574	0.003582107	0.004843918	0.739506173
SEPT	6.716666667	13	5574	0.001204999	0.002332257	0.516666667
OCT	112.5	45	5589	0.020128824	0.00805153	2.5
NOV	0	0	5596	0	0	0
DEC	0	0	5606	0	0	0
	4219.433333	3861	5570	0.75760	0.6932	1.09283

CODE	Description	2012 Totals Customers affected	2012 Totals Customers Hours
1	Scheduled	1462	608.75
2	Supply Loss	0	0
3	Tree Contact	0	0.00
4	Lightning	0	0.00
5	Def. Equip.	49	40.35
6	Weather	1672	3218.77
7	Adverse Environment	8	2.67
8	Human Element	0	0.00
9	Animals, Vehicle	670	348.90
0	Unknown	0	0.00
	Total	3861	4219.44

EXHIBIT 2 – RATE BASE

2.0-Staff-3

Ref: Exhibit 2/ Tab 2/ Schedule 2 & 5 – Poles replacement

In Exhibit 2/ Tab 2/ Schedule 5/ page 79, HHI states:

> Poles are prioritized for replacement based upon age, condition and potential adverse impact on the reliability of the distribution system. Further details on pole replacements can be found at E2.T2.S8.

However HHI did not provide data or information on the current age and condition of the poles in E2.T2.S8.

a) Please provide the data and explain the prioritization process that HHI currently employs.

HHI response: HHI performs annual inspections of all its hydro poles within its service territory based on different factors such as age, location of pole, conditions and other factors. HHI then determines which poles should be changed within the upcoming year to maintain a reliable distribution system. Poles won't be changed if they are in good condition even if they have exceed their life expectancy.

In Exhibit 2/ Tab 2/ Schedule 2, HHI provides the actual and forecasted costs for poles replacement for Historical, Bridge and Test years. Staff has prepared a table below summarizing the costs.

	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Poles replacement costs	$28,411	$27,659	$80,902	$99,000	$89,000

b) Please explain why the poles replacement expenditures increased significantly in 2012 and are expected to increase even further in 2013 and 2014.

HHI response: HHI put in place a distribution asset management plan ("DAMP") for its upcoming cost of service application as directed by the Board.

In order the meet the requirement, the utility performed a comprehensive study of all its poles identifying age, location and equipment.

The study identified assets according to age and depreciation. Until that time HHI had no recorded data on the age of its poles in the fields. Through the DAMP, HHI is now capable of identifying poles that may need to be replaced established on life expectancy. HHI applied the typical useful life expectancy of 45 years in order to obtain the pole replacement program and budget figures.

Following the 2012/2013 annual inspections, additional poles were identified as critical and unsafe. In order to maintain a safe and reliable distribution system, HHI made the decision to replace those poles. HHI identified certain poles which were approximately 45 years old but where in better condition than a 20 year poles; this primarily due to pole location or other adverse situation. In these cases, HHI won't replace this pole regardless of its age but will monitor the pole on a yearly basis for signs of deterioration.

c) In Exhibit 2/ Tab 2/ Schedule 8, HHI indicates that 33 poles will be replaced in 2014. Please provide the number of poles replaced in 2010, 2011 and 2012 and forecast replacement for 2013.

HHI response:

Poles replaced by HHI		
	Amount	# POLE
2010	$ 28,411.00	15
2011	$ 27,659.00	14
2012	$ 80,902.00	37
2013	$ 99,000.00	40
2014	$ 89,000.00	33

d) Please identify whether HHI plans to replace all the budgeted poles in 2013 and 2014 by internal workforce or by contractor.

HHI response: HHI will use internal employees the majority of the time, but in situations where digging is necessary because of rocks or other soil conditions, HHI will outsource some work. HHI will typically outsource work which requires the use of backhoe or demolition hammer. In those situations both internal workforce and contractor are used. Since seventy-five percent of the town is built on rocky soil, therefore digging can be troublesome and often affects the total price of pole replacement. The use of contractors has been included in the utility's budget.

2.0-Staff-4

Ref: Exhibit 2/ Tab 1/ Schedule 4 – 2012 Incremental Capital Module ("ICM")

On page 9 of the above reference, HHI states:

> In its 2012 IRM application, HHI applied to recover the revenue requirement associated with the incremental capital costs of $1,517,813 associated with the replacement of existing transformers with a new 25MVA in addition to the incremental capital costs of $712,909 associated with the above mentioned 44kV substation.

a) Please confirm whether the replacement of existing transformers with a new 25MVA is for HHI's 110 kV station.

   HHI response: Yes. This was approved in HHI's ICM application EB-2011-0173.

b) Please provide the actual capital expenditures for the work that HHI requested in its 2012 IRM application for both the 110kV and 44kV substations.

   HHI response: The total costs for the 44KV substation is $790,136.64. The main reason for the variance of $78,136.64 between the approved amount of $712,000 and actual expenditures of $790, 137 was due to poor soil condition. A full 6 days of extra works was required in order to build all foundation and concrete bases. An engineer was brought in to evaluate the soil condition and stability to ensure safety. Furthermore, the utility had to secure the existing structures since the soil around them was draining during digging which was a major source of concern.

CAPITAL EXPENDITURES for SUB 44KV

CONCRETE	SORBWEB SYSTEM	FENCING	EXCAVATION HAWKESBURY TRANSPORT	ENGINEERING STUDY	LINE RELOCATION COSTS HYDRO ONE
SUB 44KV	SUB 44KV	SUB 44KV	SUB 44KV	SUB 44KV	SUB 44KV
75,907.00	74,176.80	4,348.00	14,264.29	20,218.70	17,213.93
SPROULE POWERLINES	**HD SUPPLY UTILITIES**	**PIONEER TRANSFOR MERS**	**GENERAL ELECTRIC**	**MISC.**	**GRAND TOTAL**
SUB 44KV	SUB 44KV	SUB 44KV	SUB 44KV	SUB 44KV	
30,010.08	50,980.70	443,610.00	56,900.00	2,507.14	**790,136.64**

The total expenditures for the 110KV substation as of September 30, 2013, are $376,006.65. All engineering work has been completed and circuit switchers have been paid. HHI is in the process of preparing the grounds to build a control shed, an oil containment and concrete base in order to bring in the new 25 MVA transformer.

CAPITAL EXPENDITURES for SUB 110KV

ENGINEERING STUDY	BPR SUB 115KV RETROFIT STUDY	TRANSFORMER ASSESSMENT GENERAL ELECTRIC	FENCING Clôtures SDG	HYDRO ONE Connection Study Agreement	SIEMENS	GRAND TOTAL
SUB 115KV	SUB 115KV	SUB 115KV	SUB 115KV	SUB 115KV	SUB 115KV	
63,980.41	104,216.24	9,400.00	1,645.00	60,000.00	136,765.00	**376,006.65**

c) If the work for the two stations is not completed, please provide the latest estimated in-service dates.

HHI response:

- 44KV - Status complete
- 110KV - Estimated in service date is April 2014

d) Please confirm whether the gross book value and the accumulated depreciation for the above transformer projects reflected in rate base correspond to the actual capital expenditures. –

HHI response: Because the application was filed in early 2013, the amount of $800,000 for the 44KV was a projection. The actual net book value is in the amount of $790,136.64.

The gross book value and the accumulated depreciation of $1,547,900 for the 110KV correspond to the expected/estimated approved project costs. HHI expects that by the end of the year, eighty percent (80%) of the project costs will have been spent which is an expected expense of $ 1,200,000. Additional expenses will be incurred in early 2014 for an estimated service date of April.

e) Please compare actual capital expenditures with the Board-approved amounts as stated in EB-2011-0173 for the works related to the above two stations and provide an explanation for variances.

HHI response: For the Sub 44KV, please see description under Item b) and for the 110KV see table at the next page.

SUB 110 KV

	INITIAL BUDGET	ACTUALS	VARIANCE	EXPECTED BEFORE YEARD END
HONI REVIEW	$25,000.00	$25,000.00	$0.00	
HONI CAPITAL WORK NEW TAKE OFF POLE	$100,000.00	$35,000.00	$65,000.00	$35,000.00
MAJOR EQUIPEMENT				
NEW TRANSFORMER 110KV 15/20/25 MVA	$738,630.00	$0.00	$738,630.00	$472,000.00
CIRCUIT SWITCHER	$131,000.00	$136,765.00	-$5,765.00	
NEW 12.4KV SWITCH	$10,000.00		$10,000.00	
NEW CABINET AND RELAYS	$0.00			
NEW 110KV STRUCTURE				
NEW STRUCTURE ASSEMBLY	$10,360.00		$10,360.00	$10,360.00
NEW INSULATORS	$9,382.00		$9,382.00	$9,382.00
NEW 110 KV CABLES	$8,363.00		$8,363.00	$8,363.00
110 KV STRUCTURE AND CIRCUIT SWITCHER GROUNDING	$3,600.00		$3,600.00	$3,600.00
NEW 12.4 KV STRUCTURE				
NEW STRUCTURE 15 KV ASSEMBLE	$5,180.00		$5,180.00	
CABLE TRAY FOR CONTROL CABLES	$1,204.00		$1,204.00	
CONDUIT FOR CONTROL CABLES	$2,792.00		$2,792.00	
NEW CONTRO CABLE	$2,000.00		$2,000.00	
NEW 12.47 KV CABLES	$8,636.00		$8,636.00	
12.47 KV STRUCTURE GROUNDING	$2,450.00		$2,450.00	
CONSTRUCTION				
CIMENT TRANSFORMER BASE	$18,296.00		$18,296.00	$18,296.00
OIL CONTAINMENT	$65,872.00		$65,872.00	$65,872.00
CIMENT BASE CIRCUIT SWITCHER	$10,000.00		$10,000.00	$10,000.00
FENCE	$6,824.00	$1,645.00	$5,179.00	$0.00
OTHER CIVIL (MOVE SHED)	$5,000.00		$5,000.00	$5,000.00
MOVE OLD TRANSFORMER	$15,000.00		$15,000.00	
CONNECT TRANSFORMER	$27,067.50		$27,067.50	
TRANSFORMER GROUNDING	$2,252.00		$2,252.00	
P&C TESTING	$7,500.00		$7,500.00	
CONTRACTOR MARK-UP	$15,781.15		$15,781.15	
LEGAL & ENGINEERING				
P.ENG/RETROFIT STUDY	$80,000.00	$104,216.24	-$24,216.24	$20,000.00
SOIL TESTING	$7,375.00		$7,375.00	$7,375.00
ENG STUDY (INITIAL)		$63,980.41	-$63,980.41	
GE Assessment		$9,400.00	-$9,400.00	
CONTINGENCY: BPR OMITED ALL CONTROL PANELS IN NEW SHED AND THE SHED ITSELF	$197,975.65		$197,975.65	$200,000.00
TOTAL	$1,517,540.30	$376,006.65	$1,141,533.65	$865,248.00
			TOTAL EXPECTED DEC 31, 2013	$ 1,241,254.65

f) Based on the actual capital expenditures for the two stations and the latest estimated in-service date, please re-calculate the incremental revenue requirement using the ICM work form and compare to the rate rider revenue collected.

HHI response: Populating the ICM model requires a considerable amount of time. HHI does not feel like this an exercise worth doing given the fact that the

HHI's ICM was approved as part of a previous proceeding. As mentioned above, HHI expects that 80% of the costs will have been spent by the end of the year. In addition, HHI's rate rider established in 2012 does not cover the total costs of the project. Un-anticipated additional costs totalling $200,000 were not factored in the rate-rider.

HHI's ICM rate rider remains in effect until January 1, 2014, when the new 2014 rates will come into effect. As mentioned above, HHI estimates that approximately eighty percent (80%) of all of the project expenditures will have been incurred by the end of the year. As of October 31, 2013, HHI had collected $311,000 through the ICM rate rider. Expenses to date are $376,000 and are increasing due to unexpected costs (such as poor soil conditions). HHI estimates that it will have incurred nearly 1.2 million by the end of the year

2.0-Staff-5

Ref: Exhibit 2/ Tab 2/ Schedule 5 – Station

On page 66 of the above reference, HHI lists three of the projects for its 2014 capital program:

- Regular Expenditures on the New 55T1 and 55T2 and 55T3 ($25,000)
- Regular Expenditures on 43T2 ($10,000)
- Regular Maintenance of 44kV substation ($60,000)

a) Please confirm whether the above projects were approved as part of the ICM expenditures.

HHI response: The above projects were not approved as part of the ICM expenditures

b) If not, please explain the difference between the projects above and the approved ICM project.

HHI response: Regular expenditures on the new 55T1 (existing transformer) and 55T2 (existing transformer) and 55T3 (new transformer) ($25,000)
The expenditure of $ 25,000 is for on-going betterments and upkeep to the existing assets. Even though we are revamping the 110KV station, we still have two (2) transformers on site, tap changers and other equipment that we need to maintain on an annual basis. The 55T1 and 55T2 will still be on site after project

is completed. The 55T1 will be used as our second transformer, and the 55T2 will be on potential as a spare in case the 55T1 fails. Evidently the 55T1 has to be in good condition since it will be activated. The 55T2 must also be in a state that will permit a quick replacement of the 55T1 if needed. Once this is all in place, HHI will have the capacity and most importantly the redundancy to assure our customers ongoing power. Oil testing and inspection by General Electric will determine if maintenance is required for safety and reliability.

Regular Expenditures on 43T2 (new transformer of sub 44KV) ($10,000)

The expenditure of $10,000 is for an inspection of the 43T2 done by General Electric to determine if maintenance is required for safety and reliability on the existing structure, insulator etc.

Regular Maintenance of 44kV substation ($60,000)

HHI is seeking approval to send the faulty transformer to a workshop for internal diagnostic for the reason that it is producing high combustible gases. HHI is of the opinion that the repair is mandatory in order to obtain redundancy. The amount of $60,000 is an estimate of the cost to send the transformer to Stoney Creek for an inspection. At the time of our first submission of this filling, HHI did not have a quote price for repairs.

HHI did obtain a quotation price following our first submission which resembles the estimated amount of $ 60,000. Please understand that the condition of the transformer and the causes of those high gases will be known only once the internal inspection at Stoney Creek is completed. The total budget price at the present time for a complete rewind (not overall) is approximately $ 190,000. Therefore, once in the shop, if this transformer needs a complete rewind, the total estimated expenditure would be approximately $ 250,000 comprised of transportation costs to send and return the transformer, inspection costs and rewind costs.

For instance, to make evident the importance of redundancy to HHI and its customers, on July 5, 2013, its new 10 MVA pioneer transformer was found defective after only fourteen (14) months in service. According to the actual diagnostic the tap changer was the cause. Fortunately HHI had their old transformer (the one that produces high gases). HHI was able to re-energize the transformer and supply its customers with electricity. Without this second transformer, HHI would have been in a critical situation since the approximate time for building a transformer is nine (9) to twelve (12) months. Short of this second transformer, HHI's only option would have been to rent one from Hydro One at extremely high prices.

HHI strongly believes that the transformer must be repaired to assure its customers sufficient capacity and more important, ongoing supply of electricity. If the Board approves the expenditure for the diagnostics, HHI would seek recovery of the costs related to the complete refurbishing of the old transformer in a future rate application.

2.0-Staff-6

Ref: Exhibit 2/ Tab 2/ Schedule 5 – Transformer – 2014 Capital Expenditures

On page 70 of the above reference, HHI states:

> No discussion in early 2013 on possible system expansion (Subdivision). It has been HHI's experience to see these projects evolve early in the New Year. HHI must have the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure.

a) Please clarify what projects that HHI is expecting to evolve.

HHI response: HHI budgeted for two additional connections to existing subdivisions totaling approximately six (6) lots. This estimate is based on discussions with the developer and is still as of the date of these responses the best known information of HHI.

b) In regard to system expansion, what is the extent (number of houses) of the expansion HHI is expecting?

HHI response: HHI was informed by a developer of an upcoming project of six (6) new lots and has to budget some assets expenses in order to respond to those developer's requests. In some cases these projects do occur, while others are postponed. HHI has no control on investments performed by third parties.

c) Is HHI expecting a capital contribution from the developer? If so, how much is it?

HHI response: If the project does occur, and when it does, HHI will input all related costs in the "Economic Evaluation Model" to determine the contribution by the developer. In past experience this contribution is approximately 90% of total expenditures.

d) Please confirm that the capital contribution has not been included in rate base.

HHI response: Confirmed

2.0-Staff-7

Ref: Exhibit 2/ Tab 1/ Schedule 2/ Page 6 – Rate Base Variance

The 2013 Working Capital Allowance shows an increase of $996,242, which represents a 63% increase as compared to 2012. HHI explained that the Working Capital Allowance increase is proportional to the increase in OM&A. However in Exhibit 4/ Tab 1/ Schedule 2, the 2013 OM&A increase is $126,320 (12.6%) as compared to 2012.

a) Please provide the reason(s) for the remainder of the increase in Working Capital Allowance in 2013.

HHI response: The main driver behind the increase in Working Capital Allowance is the projections of the commodity. HHI has used what it thinks is the approved method of calculating the commodity. The utility essentially used Table ES-1 from current RPP report along with a weighting factor for RPP vs Non-RPP. HHI is not aware of any other method of projecting its commodity for the bridge and test year.

	2014	2013	2012	2011	2010	2010BA
4705-Power Purchased	$13,569,587	$13,527,391	$7,247,634	$7,639,787	$7,891,901	$10,507,350
	0%	87%	-5%	-3%	-25%	
Increase from last COS	29%					

b) Please provide a calculation as provided in Exhibit 3/ Tab 3/ Schedule 8 to illustrate the Power Supply Expense for 2012.

HHI response: The information requested is presented at the next page. The table shows both the Actual 2012 cost of power as well as 2012 projections using the Regulated Price Plan Price Report May 1, 2011 to April 30, 2012 Ontario Energy Board April 19, 2011, in other words, the projected cost of power had HHI filed a cost of service in 2012.

2012 Power Supply Expense

Determination of Commodity

			2012 Actual kWh's	
Customer Class Name		**2012 Actual kWh's**	**non-RPP**	**RPP**
Residential		51,132,834	-	51,132,834
General Service < 50 kW		18,531,354	-	18,531,354
General Service > 50 to 4999 kW		77,875,019	77,875,019	0
Unmetered Scattered Load		214,901		214,901
Sentinel Lighting		102,354		102,354
Street Lighting		1,355,855	1,355,855	
TOTAL		**149,212,317**	**79,230,874**	**69,981,443**
%		*100.00%*	*53.10%*	*46.90%*

Forecast Price

HOEP ($/MWh)				$43.41		**Regulated Price Plan Price Report May 1, 2011 to April 30, 2012 Ontario Energy Board April 19, 2011**
Global Adjustment ($/MWh)				$28.22		
Adjustments						
TOTAL ($/MWh)				**$71.63**	**$72.98**	
$/kWh				***$0.07163***	***$0.07298***	
%				53.10%	46.90%	
WEIGHTED AVERAGE PRICE		**$0.07226**		**$0.0380**	**$0.0342**	

Electricity Projections

(loss adjusted)

				2012 Commodity Projections			2012 Actual
Customer		**Revenue**	**Expense**				
Class Name		USA #	USA #	Volume	rate ($/kWh):	Amount	
Residential	kWh	4006	4705	53,899,862	0.07226	$3,894,974	
General Service < 50 kW	kWh	4010	4705	19,534,169	0.07226	$1,411,601	
General Service > 50 to 4999 kW	kWh	4035	4705	82,089,188	0.07226	$5,932,024	
Unmetered Scattered Load	kWh	4010	4705	226,530	0.07226	$16,370	
Sentinel Lighting	kWh	4025	4705	107,893	0.07226	$7,797	
Street Lighting	kWh	4025	4705	1,429,226	0.07226	$103,280	
TOTAL				**157,286,868**		**$11,366,046**	**$7,247,634**

Transmission - Network

(loss adjusted)

				2012 using LF and Actual Rates			2012 Actual
Customer		**Revenue**	**Expense**				
Class Name		USA #	USA #	Volume	Rate	Amount	
Residential	kWh	4066	4714	53,899,862	0.0065	$350,349	

General Service < 50 kW	kWh	4066	4714	19,534,169	0.0059	$115,252	
General Service > 50 to 4999 kW	kW	4066	4714	206,655	2.4121	$498,473	
Unmetered Scattered Load	kWh	4066	4714	226,530	0.0059	$1,337	
Sentinel Lighting	kW	4066	4714	284	1.8123	$515	
Street Lighting	kW	4066	4714	3,748	1.8117	$6,790	
TOTAL				**73,871,249**		**$972,715**	**$931,292**

Transmission - Connection

(loss adjusted)

				2012 using LF and Actual Rates			2012 Actual
Customer		**Revenue**	**Expense**				
Class Name		USA #	USA #	Volume	Rate	Amount	
Residential	kWh	4068	4716	53,899,862	0.0031	$167,090	
General Service < 50 kW	kWh	4068	4716	19,534,169	0.0027	$52,742	
General Service > 50 to 4999 kW	kW	4068	4716	206,655	1.1064	$228,643	
Unmetered Scattered Load	kWh	4068	4716	226,530	0.0027	$612	
Sentinel Lighting	kW	4068	4716	284	1.7464	$496	
Street Lighting	kW	4068	4716	3,748	0.8553	$3,206	
TOTAL		**0**	**0**	**73,871,249**		**$452,788**	**$430,694**

Wholesale Market Service

(loss adjusted)

				2012 using LF and Actual Rates			2012 Actual
Customer		**Revenue**	**Expense**		**rate ($/kWh):**	**0.0052**	
Class Name		USA #	USA #	Volume		Amount	
Residential	kWh	4062	4708	53,899,862	0.00520	$280,279	
General Service < 50 kW	kWh	4062	4708	19,534,169	0.00520	$101,578	
General Service > 50 to 4999 kW	kWh	4062	4708	82,089,188	0.00520	$426,864	
Unmetered Scattered Load	kWh	4062	4708	226,530	0.00520	$1,178	
Sentinel Lighting	kWh	4062	4708	107,893	0.00520	$561	
Street Lighting	kWh	4062	4708	1,429,226	0.00520	$7,432	
TOTAL		**0**	**0**	**157,286,868**		**$817,892**	

Rural Rate Protection

(loss adjusted)

				2012 using LF and Actual Rates			2012 Actual
Customer		**Revenue**	**Expense**		**rate ($/kWh):**		
Class Name		USA #	USA #	Volume		Amount	
Residential	kWh	4062	4730	53,899,862	0.00110	$59,290	
General Service < 50 kW	kWh	4062	4730	19,534,169	0.00110	$21,488	
General Service > 50 to 4999 kW	kWh	4062	4730	82,089,188	0.00110	$90,298	
Unmetered Scattered Load	kWh	4062	4730	226,530	0.00110	$249	
Sentinel Lighting	kWh	4062	4730	107,893	0.00110	$119	
Street Lighting	kWh	4062	4730	1,429,226	0.00110	$1,572	
TOTAL		**0**	**0**	**157,286,868**		**$173,016**	**$880,494**

LV Charge

				2012 using LF and Actual Rates		
Customer		**Revenue**	**Expense**		**2013**	
Class Name		USA #	USA #	Volume	Rate	Amount
Residential	kWh	4075	4750	51,132,834	$0.0004	$20,453
General Service < 50 kW	kWh	4075	4750	18,531,354	$0.0004	$7,413
General Service > 50 to 4999 kW	kW	4075	4750	206,655	$0.1369	$28,291
Unmetered Scattered Load	kWh	4075	4750	214,901	$0.0004	$86
Sentinel Lighting	kW	4075	4750	284	$0.2162	$61
Street Lighting	kW	4075	4750	3,748	$0.1059	$397
TOTAL		**0**	**0**	**70,089,776**		**$56,701**

Projected Power Supply Expense						**$13,839,157**	**$9,546,814**

2.0-Staff-8

Ref: Exhibit 2/ Tab 2/ Schedule 1 – Green Energy Plan

HHI did not submit its Green Energy Plan to the OPA for review and has therefore not filed a letter of comment ("OPA Comment Letter") as it is required to do as part of the basic Green Energy Plan filing. The matter was raised by the Board in its letter to HHI dated, June 24, 2013. In response, HHI stated:

> "*As such, it was decided that the utility would file a very basic plan for the single purpose of satisfying the Board's requirements.* ***Having the OPA review a basic generic GEA application which reflects a lack of interest in Hawkesbury' service area was deemed unnecessary***." [Emphasis added]

a) Board staff observes that one of the benefits of an OPA review are that it allows for co-ordinated planning of renewable generation investments – a key aspect in achieving the goals of the Green Energy Act. HHI has stated that it did not submit its Green Energy Plan for OPA review on grounds that such a review was "unnecessary". Given the benefits of an OPA review and that the filing of the OPA Comment Letter is an established filing requirement, please elaborate on your earlier response and explain why HHI believes the OPA's review of its Green Energy Plan is "unnecessary".

   HHI response: Ontario's Green Energy Act (GEA) was created to expand renewable energy generation, encourage energy conservation and promote the creation of clean energy jobs. On the topic of green jobs, the utility feels that unless the government decides to stimulate Hawkesbury's economy by sponsoring job creation (which seems unlikely) the town and surrounding area will remain unaffected by this aspect of the legislation.

   On the topic of "coordinated planning of renewable generation investments" as mentioned in the application, there is a lack of interest in renewable energy in Hydro Hawkesbury's service territory. Hawkesbury currently sits in the middle of an economically depressed region where hundreds of manufacturing jobs over the past decade have disappeared. The focus of the area is to remain afloat as opposed to focusing on renewable energy.

   As mentioned in the application, the utility currently has 4 microFIT connections and anticipates little change in the future. It is HHI's opinion that "coordinated planning of renewable generation investments" in this particular case is deemed unnecessary.

b) The OPA's review typically involves the review of the following 4 topics: Status of FIT and micro-FIT applications received by a distributor and an estimate of future applications that are expected; identification of upstream transmission constraints; and, identification of opportunities for integrated planning solutions. In the absence of the OPA Comment Letter the Board has no way of confirming whether the information contained in HHI's Green Energy Plan with respect to the above noted topics is accurate. In the absence of an OPA Comment Letter, is HHI able to provide any additional evidence that will allow the Board to confirm that the information contained in the Green Energy Plan with respect to the noted topics is acceptable to the OPA?

HHI response:

1) **Status of FIT and micro-FIT applications received by a distributor and an estimate of future applications that are expected;** The GEA plan presented as part of the application states the following;

> *Since the introduction of the Feed-in-Tariff (FIT) program, HHI has connected a total of:*
>
> *• 4 MicroFIT contracts issued*
>
> *The distribution system has been unaffected by the projects connected thus far. The number of connections has continued on a slow pace and it is likely that the rate of connections will decrease slightly due to the decrease in the contract pricing offered by the Ontario Power Authority and the overall lack of interest in the service territory.*
>
> *Overall, HHI's distribution system has been determined to be adequate to accept the renewable generation that is anticipated. There are no known barriers within HHI's distribution system for projects that are serviced by its own municipal substations.*

2) **Identification of upstream transmission constraints.** As indicated in the application, being an embedded utility, HHI must consult with Hydro One on each connection request. This gives Hydro One an opportunity to assess and address capacity issues within its service territory. HHI will continue to work co-operatively with Hydro One as new connections are added to the system. HHI also hired Stantec to conduct a high level review and analysis of the

distribution system to ensure that it was capable of accommodating any fit or microFIT connections. The one page letter is presented at Appendix A of these responses.

3) **Identification of opportunities for integrated planning solutions:** As also mentioned in the application, there is a lack of interest in renewable energy in Hydro Hawkesbury's service territory. Any type of planning be it "co-ordinated" or "integrated" of renewable generation investments" is deemed excessive in the case of a utility which anticipates no more than a few connections in the future.

c) Given the response to the Board's June 24, 2013 letter, please confirm that HHI has not had any discussions with the OPA in relation to the development of its Green Energy Plan. Alternately, if HHI has had discussions with the OPA in relation to the development of its Green Energy Plan, please provide a summary of the discussions and identify any concerns that may have been expressed by the OPA on this matter.

HHI response: HHI has not discussed the Green Energy Plan with the OPA

2.0-Staff-9

Ref: Exhibit 2/ Tab 2/ Schedule 1/ Page 8 – Green Energy Plan; Ontario Regulation 330/09

At the above reference HHI states:

"…the utility does not expect any material investments in renewable infrastructure. The utility does expect modest growth in renewable generation and minor system expansion/upgrades to accommodate renewable generation but does not seek to fund those expansions through this GEA Plan."

a) Are the "expansion/upgrade" investments that are referenced above included in HHI's Test Year capital expenditure plan?

HHI response: HHI has reconsidered this statement and is not attesting that it does not foresee any investments in infrastructures to accommodate renewable energy.

b) If the investments are included in the Test Year capital expenditure budget, please identify the investments and explain why these investments are not identified in the Green Energy Plan, as required under the Board's filing requirements.

HHI response: see response to b) above

c) If the investments are known and have been included in the Test Year capital budget, please provide the appropriate cost responsibility for the investments (as stated in section 3 of the Distribution System Code) and HHI's proposal for sharing of costs under Ontario Regulation 330/09.

HHI response: see response to b) above

2.0-Staff-10

Ref: Exhibit 9/ Tab 1/ Schedule 1/ Page 12 - Disposition of Account 1535 – Smart Grid OM&A Deferral Account

HHI is proposing to dispose of Account 1535 – Smart Grid OM&A deferral account with the balance of $1,901. At the above reference HHI states:

"… includes expenses associated with preparing the Smart Grid Portion of a GEA plan.

……costs incurred in this variance account were in relation to a study that was done back in 2010 to determine if the substation had enough capacity to accommodate FIT and MicroFIT connections."

If the expenses are associated with preparing the Smart Grid Portion of a GEA plan, please identify which portion of the GEA plan is related to these expenses and explain why such expenses are related to FIT and MicroFIT connections.

HHI response: Costs incurred in this variance account were in relation to a study that was done by Stantec back in 2010 to determine if the substation had enough capacity to accommodate FIT and MicroFIT connections. HHI doesn't have any other clarifications for this expense other than the one identified above. If OEB finds that it should have been recorded in account 1532 as discussed in our conference call, HHI will do the revisions. Nonetheless, HHI will seek recovery of this expense anyhow since account 1532 forms part of RSVA Group 2 Accounts.

2.0-Staff-11

Ref: Exhibit 2/ Tab 3/ Schedule 1 – Service Quality and Reliability Performance

In Table 12 of the above reference, HHI provides service reliability indices for 2010, 2011, and 2012. Please explain why the loss of supply adjusted service reliability indices changed notably in 2011 as compared to 2010 and 2012.

> **HHI response**: In 2011 HHI experienced more outages caused by the loss of supply from Hydro One. Unfortunately, HHI has no control over Hydro One's asset or operations. The exact cause of outages can be obtained through Hydro One.
>
> Please find below tables demonstrating loss of supply from Hydro One.

LOSS OF SUPPLY			
DATE	CUSTOMERS AFFECTED	CUSTOMER HOURS	STATION AFFECTED
25-Jan	1329	3655	44KV
31-Jan	1329	1196	44KV
24-Feb	4093	1023.25	110 KV
8-Jul	1329	730.95	44KV
3-Sep	4093	341.08	110KV
TOTAL 2011	12173	6946.28	

HYDRO HAWKESBURY SYSTEM & SERVICE RELIABILITY INDICES INCLUDING LOSS OF SUPPLY		
YEAR	NUMBER CUSTOMER HOURS	NUMBER OF CUSTOMER
2010	1898	759
2011	6946	12173
2012	1088	109

2.0-VECC – 2

Reference: Exhibit 2, Tab 1, Schedule 5 / (E2.T1.S4)

a) The continuity schedule at Appendices_rev20130613 (schedule 5) shows that in 2012, $601,817 was added into account 1860 - smart meters. It also shows an additional $17,082 added to rate base under this category. Please explain the additional $17,082 in smart meter asset acquisition. Is the 17k part of the 601k?

HHI response: The $601, 817 capital expenditures transferred into rate base as approved in EB-2012-0198 and the $17,082 expense is the actual smart meter acquisition during the year.

b) Please explain why $254,843 in stranded meters is in the opening balance for 2014. Please provide the rate base and revenue requirement adjustment assuming the 2014 opening balances for stranded meters (asset and depreciation) are removed.

HHI response: In its Smart Meter Application, HHI proposed not to dispose of stranded meters by way of stranded meter rate riders at that time, but to deal with disposition in its next COS application, scheduled in 2014 rates.

Board staff submitted that HHI's proposal is also compliant with Guideline G-2011-0001 and as such HHI has removed the value of its stranded meters in 2014.

The $254,843 is the gross book value at that time.

2.0-VECC – 3

Reference: Exhibit 2, Tab 1 (E2.T1.S4)

a) Please provide a breakdown by USoA account of the $2,230,722 in ICM spending, showing the adjustment to rate base in 2014. In doing this please also show how the collected ICM rate rider revenue is used (or not) to offset the adjustment to rate base for the assets in question.

HHI response: As explained in the application, due to the lack of instructions from the Board regarding the treatment of revenues related to ICM, HHI has not made any offsetting adjustment to its Rate Base to reflect revenues collected through its ICM rate rider. HHI understands that other utilities have made various adjustments to reflect the impact of ICM revenues however; HHI would prefer to wait for direction from the Board on how to treat these balances as opposed to take instruction from interveners.

2.0-VECC – 4

Reference: Exhibit 2, Tab 1 (E2.T1.S6) / Table 13 (E4.T5.S3)

a) Are any of the adopted depreciation rates shown in Table 8 (Table 13) outside the range proposed in the Kinectrics report? If so please detail this exception and explain the materiality (in revenue requirement adjustment terms) of any deviations.

HHI response: Depreciation rates fall within the Kinectrics report

2.0-VECC –5

Reference: Exhibit 2, Tab 1 (E2.T1.S7)

a) Does HHI now bimonthly bill all its customers? When did the billing cycle change?

HHI response: HHI bills its entire customer base on a monthly basis as of December 2012.

b) What is the reduction to the need for actual working capital now that HHI bills on a monthly basis?

HHI response: None. During certain months of the year where the load is higher (such as peak summer and winter months), HHI often has to use its line of credit in order to meet its obligations to the IESO. To further reduce the utility's capital allowance would jeopardize the utility's ability to meet its financial obligations.

2.0-VECC – 6

Reference: Exhibit 2, Tab 2 (E2.T1.S9)

a) As shown in the 2011 Fixed Asset Continuity Schedule, the difference in the estimated and actual stranded meter amount appears to be related to $7,797 in meter additions made in 2011. Please explain why this investment was made if it was to be stranded in the next year – that is why were mechanical meters installed instead of smart meters?

HHI response: This cost relates to meter testing done by MSP Service Provider Peterborough, to complete IESO audit for Hawkesbury Municipal Transmission Station. This capital expenditure should have remained in account 1860. HHI has rectified this error in the appendices filed in conjunctions with these responses. The revised rates reflect this change.

2.0-VECC – 7

Reference: Exhibit 2, Tab 2 (see also 2.0-Staff-3)

a) Please explain the underinvestment in poles and associated hardware in 2008 through 2011 as compared to the 2012 and onward budgets.

HHI response: HHI performs an annual inspection of all its hydro poles within its service territory based on different factors such as age, location of pole, conditions and other factors. HHI then determines which poles should be changed within the upcoming year to maintain a reliable distribution system. Poles won't be changed if they are in good condition even if they exceed their life expectancy.

Following the 2012/2013 annual inspection, additional poles were identified as critical and unsafe. In order to maintain a safe and reliable distribution system, HHI made the decision to replace those poles.

HHI has put in place an asset management plan for the 2014 Cost of Service application as directed by the Board which resulted in a pole replacement increase. We performed a comprehensive study of all our poles identifying age, location and equipment on poles in order to populate the DAMP. The study defined poles to be replaced according to age and depreciation as we did in the past. Until that time HHI had no recorded data on the age of its poles in the fields. With the DAMP, we are now capable of identifying poles that may need to be replaced established on life expectancy. During our annual inspection we at times notice a 45 year old pole in better condition than a 20 year one; this primarily due to pole location or other adverse situation. Also, we applied the IFRS 45 year's depreciation rate in order to obtain the pole replacement program and budget figures.

2.0-VECC – 8

Reference: Exhibit 2, Tab 2

a) Please provide a description of all the buildings owned or leased by HHI, including garages and administrative offices.

HHI Response: Although HHI mentioned in the application that the office building was built in 1962, it was in fact built in 1991. HHI also owns a 44KV distribution station located on Tupper St and a 110KV municipal station located on Main St. West.

b) HHI notes that its current building was built in 1962. What plans, if any, does HHI have to replace its existing building(s)?

HHI Response: As mentioned above, the building was built in 1991 therefore HHI does not plan to replace it. HHI did some renovations in 2013; minor repairs were done to the leaking roof to extend its life until 2016 and to prevent further water infiltration. Two heating/conditioning units were replaced also in 2013 while the remaining three will be change in 2014.

2.0- VECC - 9
Reference: Exhibit 2, Tab 2, pg.52

a) Please update the 2013 capital budget to show (3 columns) the amount spent to-date on each project, the forecast remaining to be spent on the project and the project's expected or actual in-service date.

HHI Response: See table below

Capital Budget- 2013
HAWKESBURY HYDRO INC.

GL ACCOUNT NUMBER.	DESCRIPTION	BUDGET	ACTUALS 2013 AS OF SEPT 30	FORECAST (ADDITION) TILL YEAR END	TOTAL EXPENSES	IN SERVICE DATE
			DISTRIBUTION PLANT			
1815-000	Transf. Station Equipment 115kv	$1,547,900.00	$0	$ 1,242,000.00	$ 1,242,000.00	Apr-14
1820-000	Distrib. Station Equipment 44KV	$ 800,000.00	$0	$ 800,000.00	$ 800,000.00	IN SERVICE
1830-000	Poles, Towers , Fixtures	$ 99,000.00	$42,320	$ 50,400.00	$ 92,720.00	31-Dec-13
1835-000	OH conductors and devices	$ 25,000.00	$980	$ 12,000.00	$ 12,980.00	31-Dec-13
1840-000	UG Conduit	$ 500.00	$0	$ 500.00	$ 500.00	
1845-000	UG Conductor and Devices	$ 17,000.00	$0	$ 3,000.00	$ 3,000.00	31-Dec-13
1850-000	Line Transformer	$ 28,000.00	$16,152	$ 3,500.00	$ 19,652.00	31-Dec-13
1855-000	Services	$ 3,000.00	$612	$ 500.00	$ 1,112.00	31-Dec-13
1860-000	Meters	$ 3,500.00	$4,101	$ 400.00	$ 4,501.00	31-Dec-13
	SUB TOTAL (DISTRIBUTION PLANT)	$2,523,900.00	$ 64,165.00	$ 2,112,300.00	$ 2,176,465.00	
			GENERAL PLANT			
1908-000	Building and Fixtures	$ 37,500.00	$38,205	$ -	$ 38,205.00	COMPLETE
1915-000	Office Furniture and equipment	$ 5,700.00	$5,599	$ 101.00	$ 5,700.00	31-Dec-13
1920-000	Computer Equipment -Hardware	$ 3,000.00	$1,897	$ 900.00	$ 2,797.00	31-Dec-13
1611-000	Computer Software	$ 28,000.00	$6,725	$ 20,000.00	$ 26,725.00	31-Dec-13
1940-000	Tools, Shop, and Garage Equipment	$ 3,000.00	$299	$ 1,000.00	$ 1,299.00	31-Dec-13
1950-000	Power Operated Equipment	$ 2,000.00	$405	$ 1,100.00	$ 1,505.00	31-Dec-13
	SUB TOTAL (GENERAL PLANT)	$ 79,200.00	$ 53,130.00	$ 23,101.00	$ 76,231.00	
	TOTAL EXPENSES CAPITAL	$2,603,100.00	$ 117,295.00	$ 2,135,401.00	$ 2,252,696.00	

2.0-VECC – 10

Reference: Exhibit 2, Tab 2, pg. 70

a) HHI has budgeted $12,500 for transformers related to an expected subdivision. The evidence notes that a capital contribution will be required related to this expenditure. Please provide the estimated contribution.

HHI response: Please refer to Board interrogatories 2.0-Staff-6.

b) What were the capital contributions in 2010 through 2014 (forecast).

HHI response: At the time of the application HHI inadvertently omitted the capital contributions for 2013 and 2014 from the appendices. Please find below the projections that should have been included in the application. The appendices filed in conjunction with these responses reflect this change.

CAPITAL CONTRIBUTION FROM DEVELOPPERS		
2010	$	74,300.00
2011	$	-
2012	$	110,041.00
2013	$	20,113.00
2014	$	27,450.00

2.0-VECC – 11

Reference: Exhibit 2, Tab 2, pg. 82 (E2.T2.S8)

a) Had HHI completed an Asset Management Plan prior to the 2013 Plan filed in the evidence?

HHI response: No

b) Please provide the forecast capital expenditures included in the last cost of service filing of HHI.

HHI response: This information is presented at the next page.

B3 Net Capital Asset Balances

Account Description	2006 EDR Approved - Ending Balances Gross Assets	Accumulated Amortization	Net Book Value	2006 Actual - Ending Balances Gross Assets	Accumulated Amortization	Net Book Value
1805-Land	10,000		10,000	20,000		20,000
1806-Land Rights	8,588	-2,295	6,293	8,588	-2,608	5,980
1815-Transformer Station Equipment - Normally Primary above 50 kV	56,416	-30,983	25,433	281,524	-46,155	235,369
1820-Distribution Station Equipment - Normally Primary below 50 kV	151,715	-35,358	116,357	152,376	-59,476	92,900
1830-Poles, Towers and Fixtures	255,254	-69,624	185,630	284,040	-116,733	167,307
1835-Overhead Conductors and Devices	320,205	-72,396	247,809	353,823	-130,547	223,276
1840-Underground Conduit	113,060	-21,664	91,396	113,414	-36,441	76,973
1845-Underground Conductors and Devices	172,400	-32,755	139,645	174,724	-55,324	119,400
1850-Line Transformers	279,164	-92,082	187,082	283,501	-127,321	156,180
1855-Services	14,185	-1,113	13,072	17,800	-2,684	15,116
1860-Meters	218,045	-58,537	159,508	221,805	-95,431	126,374
1905-Land	28,300		28,300	28,300		28,300
1908-Buildings and Fixtures	820,347	-74,504	745,843	822,675	-118,590	704,085
1915-Office Furniture and Equipment	8,097	-5,097	3,000	14,168	-7,129	7,039
1920-Computer Equipment - Hardware	20,309	-12,464	7,845	30,322	-21,095	9,227
1925-Computer Software	1,833	-492	1,341	22,263	-4,863	17,400
1930-Transportation Equipment	184,896	-98,158	86,738	184,896	-161,762	23,134
1940-Tools, Shop and Garage Equipment	5,912	-3,238	2,674	10,606	-5,061	5,545
1950-Power Operated Equipment				4,363	-818	3,545
1995-Contributions and Grants - Credit						
TOTAL	**2,668,726**	**-610,760**	**2,057,966**	**3,029,191**	**-992,038**	**2,037,153**

B3 Net Capital Asset Balances

Account Description	2007 Actual - Ending Balances			2008 Actual - Ending Balances		
	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value
1805-Land	20,000		20,000	20,000		20,000
1806-Land Rights	8,588	-2,608	5,980	8,588	-2,608	5,980
1815-Transformer Station Equipment - Normally Primary above 50 kV	281,524	-53,262	228,262	302,188	-60,627	241,561
1820-Distribution Station Equipment - Normally Primary below 50 kV	152,376	-69,141	83,235	152,376	-78,806	73,570
1830-Poles, Towers and Fixtures	297,192	-135,232	161,960	298,257	-152,944	145,313
1835-Overhead Conductors and Devices	355,022	-154,264	200,758	362,383	-177,004	185,379
1840-Underground Conduit	113,414	-42,363	71,051	113,634	-48,289	65,345
1845-Underground Conductors and Devices	175,905	-64,419	111,486	202,283	-74,065	128,218
1850-Line Transformers	288,119	-141,218	146,901	310,028	-155,173	154,855
1855-Services	19,413	-3,429	15,984	21,013	-4,237	16,776
1860-Meters	222,885	-110,245	112,640	224,822	-125,120	99,702
1905-Land	28,300		28,300	28,300		28,300
1908-Buildings and Fixtures	824,124	-135,575	688,549	824,124	-152,574	671,550
1915-Office Furniture and Equipment	18,427	-8,280	10,147	25,511	-9,952	15,559
1920-Computer Equipment - Hardware	40,391	-25,969	14,422	42,614	-30,388	12,226
1925-Computer Software	49,734	-12,062	37,672	113,042	-28,089	84,953
1930-Transportation Equipment	184,896	-184,796	100	205,346	-186,174	19,172
1940-Tools, Shop and Garage Equipment	11,939	-5,902	6,037	12,648	-6,842	5,806
1950-Power Operated Equipment	4,363	-1,363	3,000	4,363	-1,908	2,455
1995-Contributions and Grants - Credit				-55,867	1,117	-54,750
TOTAL	**3,096,612**	**-1,150,128**	**1,946,484**	**3,215,651**	**-1,293,683**	**1,921,968**

B3 Net Capital Asset Balances

Amounts from sheets B1 and B2

Account Description	2009 Projection - Ending Balances			2010 Projection - Ending Balances		
	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value
1805-Land	20,000		20,000	20,000		20,000
1806-Land Rights	8,588	-2,608	5,980	8,588	-2,608	5,980
1815-Transformer Station Equipment - Normally Primary above 50 kV	372,188	-69,126	303,062	454,188	-78,937	375,251
1820-Distribution Station Equipment - Normally Primary below 50 kV	229,376	-89,754	139,622	279,376	-102,819	176,557
1830-Poles, Towers and Fixtures	347,257	-171,502	175,755	420,257	-191,694	228,563
1835-Overhead Conductors and Devices	390,383	-199,283	191,100	423,383	-222,456	200,927
1840-Underground Conduit	113,634	-54,220	59,414	113,634	-60,151	53,483
1845-Underground Conductors and Devices	219,783	-84,588	135,195	237,283	-95,811	141,472
1850-Line Transformers	323,028	-169,771	153,257	334,028	-184,167	149,861
1855-Services	21,013	-5,077	15,936	21,013	-5,917	15,096
1860-Meters	224,822	-140,032	84,790	224,822	-154,804	70,018
1905-Land	28,300		28,300	28,300		28,300
1908-Buildings and Fixtures	824,124	-169,573	654,551	849,124	-186,822	662,302
1915-Office Furniture and Equipment	38,511	-12,610	25,901	58,011	-16,893	41,118
1920-Computer Equipment - Hardware	48,614	-35,268	13,346	59,614	-41,160	18,454
1925-Computer Software	120,042	-50,914	69,128	129,242	-74,771	54,471
1930-Transportation Equipment	205,346	-188,730	16,616	205,346	-191,286	14,060
1940-Tools, Shop and Garage Equipment	24,648	-8,364	16,284	29,648	-10,736	18,912
1950-Power Operated Equipment	4,363	-2,453	1,910	34,363	-4,873	29,490
1995-Contributions and Grants - Credit	-55,867	3,351	-52,516	-55,867	5,585	-50,282
TOTAL	**3,508,151**	**-1,450,522**	**2,057,629**	**3,874,351**	**-1,620,320**	**2,254,031**

c) Please provide the forecast capital budget for period covering the current Asset Management Plan. If no such budget was completed please explain why not?.

HHI response: See table below

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Land Rights Distribution Plant (Acct 1806)												
Transformer Station Equipment (Acct 1815)	$ 1,547,900.00	$ 25,000.00	$ 25,000.00	$ 25,000.00	$ 40,000.00	$ 35,500.00	$ 35,000.00	$ 25,000.00	$ 25,000.00	$ 35,500.00	$ 25,000.00	$ 35,000.00
Distribution Station Equipment (1820)	$ 800,000.00	$ 60,000.00	$ 30,000.00	$ 20,000.00	$ 20,000.00	$ 27,000.00	$ 30,000.00	$ 20,000.00	$ 20,000.00	$ 27,000.00	$ 20,000.00	$ 30,000.00
Poles, Towers & Fixtures (Acct 1830)	$ 99,000.00	$ 89,000.00	$ 140,000.00	$ 118,000.00	$ 112,000.00	$ 80,000.00	$ 89,000.00	$ 94,000.00	$ 80,000.00	$ 80,000.00	$ 87,000.00	$ 78,000.00
Overhead Conductors and Device (Acct 1835)	$ 25,000.00	$ 20,000.00	$ 7,000.00	$ 25,500.00	$ 7,000.00	$ 20,000.00	$ 15,000.00	$ 15,000.00	$ 5,000.00	$ 5,250.00	$ 5,512.50	$ 5,788.13
Underground Conduit (Acct 1840)	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00
Underground Conductors & Devices (Acct 1845)	$ 17,000.00	$ 17,500.00	$ 18,000.00	$ 18,500.00	$ 19,000.00	$ 19,500.00	$ 20,000.00	$ 20,500.00	$ 21,000.00	$ 21,500.00	$ 22,000.00	$ 22,500.00
Line Transformers (Acct 1850)	$ 28,000.00	$ 12,500.00	$ 13,000.00	$ 13,500.00	$ 14,000.00	$ 14,500.00	$ 15,000.00	$ 15,500.00	$ 16,000.00	$ 16,500.00	$ 17,000.00	$ 17,500.00
Services (Acct 1855)	$ 3,000.00	$ 3,100.00	$ 3,200.00	$ 3,296.00	$ 3,394.88	$ 3,496.73	$ 3,601.63	$ 3,709.68	$ 3,820.97	$ 3,935.60	$ 4,053.66	$ 4,175.27
Meters (Acct 1860)	$ 3,500.00	$ 3,500.00	$ 3,500.00	$ 3,500.00	$ 10,500.00	$ 80,000.00	$ 3,500.00	$ 3,500.00	$ 3,500.00	$ 3,500.00	$ 3,500.00	$ 3,500.00
Land General Plant (1905)												
Buildings and Fixtures (1908)	$ 37,500.00	$ 12,500.00	$ 2,000.00	$ 65,000.00	$ 2,000.00	$ 2,000.00	$ 3,000.00	$ 3,000.00	$ 3,000.00	$ 3,000.00	$ 3,000.00	$ 3,000.00
Office Furniture & Equipment (Acct 1915)	$ 5,700.00	$ 3,500.00	$ 3,600.00	$ 3,708.00	$ 3,819.24	$ 3,933.82	$ 4,051.83	$ 4,173.39	$ 4,298.59	$ 4,427.55	$ 4,560.37	$ 4,697.18
Computer Equipment Hardware (Acct 1920)	$ 3,000.00	$ 3,100.00	$ 5,000.00	$ 10,000.00	$ 6,000.00	$ 3,193.00	$ 5,150.00	$ 5,500.00	$ 10,500.00	$ 6,500.00	$ 3,288.79	$ 5,304.50
Computer Software (Acct 1925)	$ 28,000.00	$ 17,000.00	$ 17,500.00	$ 18,000.00	$ 18,500.00	$ 19,000.00	$ 19,500.00	$ 20,000.00	$ 20,500.00	$ 21,000.00	$ 21,500.00	$ 22,000.00
Transportation Equipment (Acct 1930)	$ -	$ -										
Tools, Shop & Garage Equipment (Acct 1940)	$ 3,000.00	$ 3,100.00	$ 3,200.00	$ 3,296.00	$ 3,394.88	$ 3,496.73						
Power Operated Equipment (Acct 1950)	$ 2,000.00	$ 2,000.00	$ 2,000.00	$ 2,000.00	$ 2,000.00	$ 2,000.00						
	$ 2,603,100.00	$ 272,300.00	$ 273,500.00	$ 329,800.00	$ 262,109.00	$ 314,120.27	$ 243,303.46	$ 230,383.06	$ 213,119.56	$ 228,613.14	$ 216,915.33	$ 231,965.08

EXHIBIT 3 – OPERATING REVENUE

3.0-Staff-12

Ref: Exhibit 3/ Tab 1/ Schedule 4/ Table 13 – Regression Model

The estimated model statistics shown in Table 13 indicate that Ottawa economic region Full-Time Employment ("FTE") has a negative coefficient of -1925.48 and is statistically insignificant (t = -0.60 with a p-value of 49%). It is unintuitive for consumption to be negative as it relates to economic activity.

a) Please explain why the FTE variable was retained even though it has an unintuitive sign and is statistically insignificant.

HHI response: Although the variable does not yield significant results, HHI though that it would be worthwhile keeping it since the FTE variable was used in the last Board Approved Load Forecast.

b) Was Ontario real GDP (or alternatively, given Hydro Hawkesbury's service territory, Ontario + Québec real GDP) tried as a variable of economic activity?

HHI response: HHI did not consider Quebec's real GDP as a variable. Unlike the neighbouring utilities, Hawkesbury is not a bedroom community for major centers such as Ottawa or Montreal. Over the past years, as larger commercial customers within the service territory have shut down, residents have lost their jobs and moved away to other cities where work is available. HHI is of the opinion that with the exception of weather related variables, such as Heating Degree Days, Cooling Degree Days, no other variable help accurately predict the utility's load.

c) Please re-run the regression model excluding the Ottawa region FTE model. Provide all model statistics and estimates for 2013 and 2014.

HHI response: The scenario requested is being filed in conjunction with this application. The regression results are presented in section e) of this question.

d) Provide the monthly Mean Average Percentage Error and a graph, similar to Exhibit 3/Tab 1/Graph 1 but showing the monthly actuals and predicted values based on the model run in c).

HHI response: The MAPE can be found in the table below as well as the model filed in conjunction with these responses.

Year	kWh Purchased	Adjusted	MAPE
2004	166,851,164.00	164,979,870.16	1.12%
2005	160,069,378.00	165,422,991.82	3.34%
2006	165,982,316.00	162,008,858.32	2.39%
2007	168,514,536.00	164,475,754.03	2.40%
2008	167,375,788.00	164,353,919.20	1.81%
2009	167,014,595.54	164,363,608.77	1.59%
2010	159,288,613.00	162,262,640.51	1.87%
2011	161,859,215.00	161,618,718.54	0.15%
2012	155,160,223.00	162,629,467.19	4.81%
Mean Average Percentage Error (Mape) :			**2.16%**

in column A: Actual value
in column B: Forecast value
*in column C: =IF(ABS(A2-B2)=0,0,ABS(A2-B2)/A2*100)*
calculate an average of column C (=AVERAGE(C2:Cx) and you have the MAPE in percent.

Median **1.87%**

e) Provide the same information in d) for the estimated model documented in Table 13.

HHI response: The table requested is presented below

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.923558
R Square	0.852959
Adjusted R Square	0.848717
Standard Error	749207.9
Observations	108

ANOVA

	df	SS	MS	F	Significance F
Regression	3	3.39E+14	1.13E+14	201.0953	3.86E-43
Residual	104	5.84E+13	5.61E+11		
Total	*107*	*4E+14*			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	11607122	246628.7	47.06315	6.21E-72	11118049	12096196	11118049	12096196
HDD	6148.784	350.3751	17.54915	7.36E-33	5453.977	6843.591	5453.977	6843.591
CDD	8055.12	2891.38	2.785909	0.006345	2321.405	13788.83	2321.405	13788.83
Spring Fall	-708791	171606.7	-4.13032	7.34E-05	-1049093	-368488	-1049093	-368488

3.0-Staff-13

Ref: Exhibit 3/ Tab 1/ Schedule 4/ Table 17 and 18 – Customer Forecast

a) HHI indicates that Residential counts are expected to grow by 81 from 2012 to 2014. Please explain the basis for this expectation.

HHI response: HHI used the Board accepted methodology of a Geomean to predict its customer count. HHI then reviewed the results and further adjusted its count to reflect any additional known information at the time of the filing such as new housing development.

b) In Table 17, HHI provides load forecast for Residential customers, in which the table includes an adjustment for new customers for 2013 and 2014. Please explain how the adjustment for 2014 would reflect the expectation as indicated in (a).

HHI response: Home Builders keep HHI informed of their building intentions as well as the status of any on-going building project. Based on information provided by builders, HHI increased the calculated total by an additional 6 residential customers.

c) HHI indicates that General Service < 50 counts are expected to increase by 18 from 2012 to 2014. Please explain the basis for this expectation.

HHI response: Similarly to the responses provided in a) and b), HHI reviewed the results of the Geomean calculations and based on the information known at the time of the filing, opted to add 10 GS<50 customers to the calculated totals for 2013 and 2014.

d) In Table 18, HHI provides load forecast for General Service < 50 customers, in which, the table includes an adjustment for new customers for 2013 and 2014. Please explain how the adjustment for 2014 would reflect the expectation as indicated in (c).

HHI response: Similarly to the response provided in a) and b), the adjustment reflects known information at the time of the filing or an educated judgment call on the part of the executives at the utility.

3.0-Staff-14

Ref: Exhibit 3/ Tab 1/ Schedule 4/ Table 22 and 23 – Customer Forecast

Please confirm that the entries shown in Tables 22 and 23 for Streetlights, Sentinel Lights and Unmetered Scattered Load are for connections and not for customers, as labeled.

HHI response: HHI confirms that they are connections.

3.0-Staff-15

Ref: Exhibit 3/ Tab 1/ Schedule 5/ Table 24, 25, 26 and 27 – CDM Adjustment to Load Forecast

In this Exhibit 3/ Tab 1/ Schedule 5, HHI documents the calculation of the adjustment for CDM to the load forecast. This is largely based on the methodology used in 2013 cost of service applications. HHI has included an adjustment to use gross versus net CDM savings as measured by the OPA.

In its Decision EB-2012-0113 regarding Centre Wellington Hydro's 2013 Cost of Service rates application, the Board determined that the CDM adjustment to the load forecast should be based on the "net" savings as documented in the OPA report (or in a third-party evaluation that conforms with the OPA's documentation).

a) Based on the final 2012 OPA results, if that report is available, please file a completed Appendix 2-I from the Filing Requirements for Transmission and Distribution Applications issued on July 17, 2013 as a replacement for Tables 24, 25 and 26. If not available, please calculate based on the preliminary 2012 Q4 OPA report provided in Exhibit 3/Tab 3/Appendix B. The completed Appendix 2-I should also be provided in a working Microsoft Excel format.

   HHI response: See the revised Appendix 2-I (from the Filing Requirements for Transmission and Distribution Applications issued on July 17, 2013) at the next page.

4 Year (2011-2014) kWh Target:

9,280,000

	2011	2012	2013	2014	Total
2011 CDM Programs	7.73%	7.73%	7.73%	7.73%	30.94%
2012 CDM Programs		7.38%	7.38%	7.38%	22.15%
2013 CDM Programs			15.64%	15.64%	31.27%
2014 CDM Programs				15.64%	15.64%
Total in Year	**7.73%**	**15.12%**	**30.76%**	**46.39%**	**100.00%**

kWh

	2011	2012	2013	2014	Total
2011 CDM Programs	717,718.00	717,718.00	717,718.00	717,718.00	2,870,872.00
2012 CDM Programs		685,247.00	685,247.00	685,247.00	2,055,741.00
2013 CDM Programs			1,451,129.00	1,451,129.00	2,902,258.00
2014 CDM Programs				1,451,129.00	1,451,129.00
Total in Year	**717,718.00**	**1,402,965.00**	**2,854,094.00**	**4,305,223.00**	**9,280,000.00**

From each of the 2006-2010 CDM Final Report, 2011 CDM Final Report, and the 2012 CDM Final Report, issued by the OPA for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D31 to E33. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".
The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis.

Net-to-Gross Conversion

Is CDM adjustment being done on a "net" or "gross" basis? **net**

Persistence of Historical CDM programs to 2014	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program				
2012 CDM program				
2006 to 2011 OPA CDM programs: Persistence to 2013	0	0	0	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.
These factors do not mean that CDM programs are excluded, but also reflect the assumption that impacts of 2011 and 2012 programs are already implicitly reflected in the actual data for those years that are the basis for the load forecast prior to any manual CDM adjustment.

	Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast				
	2011	**2012**	**2013**	**2014**	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0.5**	**1**	**0.5**	Utility can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Persistence of 2011 CDM programs for the full year of 2012 means that all of 2011 CDM impact is assumed to be in the base forecast before the CDM Adjustment*	*50% of 2012 CDM impact is assumed reflected in base forecast based on 1/2 year rule.*	*Full year impact of 2013 CDM programs on adjustment for 2014 load forecast*	*Only 50% of 2014 CDM impact is used based on a half year rule*	

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2014 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data, and is intended to reflect the further CDM savings that the distributor needs to achieve assuming that they meet 100% of the 2011-2014 CDM target that is a condition of their target.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner, for both the LRAMVA and for the load forecast adjustment.

	2011	2012	2013	2014	Total for 2014
			kWh		
Amount used for CDM threshold for LRAMVA (2014)	717,718.00	685,247.00	1,451,129.00	1,451,129.00	4,305,223.00
Manual Adjustment for 2014 Load Forecast (billed basis)	-	342,623.50	1,451,129.00	725,564.50	2,519,317.00
Proposed Loss Factor (TLF)	3.73%	Format: X.XX%			
Manual Adjustment for 2014 Load Forecast (system purchased basis)	-	355,403.36	1,505,256.11	752,628.06	2,613,287.52

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.

a) Please provide an update to Table 27 based on the results of a).

HHI response: The updated table can be found below.

CDM Adjustement

Actual and Weather Normalized							CDM Adjustment		
		Actual			Projected		Adjusted		
kWh	Year	2010	2011	2012	2013	2014	Share	Target	2014
Residential	kWh	50,277,839	51,273,093	51,132,834	54,299,334	54,358,933	34.53%	870,008.32	53,488,924.26
GS<50	kWh	19,562,613	18,457,375	18,531,354	19,976,859	19,548,144	12.42%	312,865.74	19,235,278.13
GS>50	kWh	80,745,583	82,739,387	77,875,019	82,095,101	82,016,390	52.10%	1,312,662.66	80,703,727.03
Streetlight	kWh	1,156,978	1,343,667	1,355,855	1,150,473	1,155,227	0.73%	18,489.28	1,136,738.07
Sentinel Lights	kWh	105,383	102,889	102,354	106,349	106,349	0.07%	1,702.10	104,646.79
USL	kWh	242,514	215,299	214,901	224,238	224,238	0.14%	3,588.90	220,649.10
Total		152,090,910	154,131,710	149,212,317	157,852,354	157,409,280	100.00%	2,519,317.00	154,889,963.38

	Year	2010	2011	2012	2013	2014	
GS>50	kW	209,711	211,681	206,655	204,590	204,394	201,122
Streetlight	kW	3,194	3,724	3,748	3,250	3,263	3,211
Sentinel Lights	kW	297	280	284	297	297	292
Total						207,954	204,626

b) If available, please provide the final 2012 OPA report.

HHI response: The report is filed in conjunction with these responses

3.0-VECC – 12

Reference: Exhibit 3, Tab 1, Schedule 2

a) Are the customer numbers shown in Table 1 year end values or average annual values?

HHI response: The customers are year-end values. HHI notes that it is unclear as to why HHI should not use year-end values since the consumption is predicted as a year-end value. HHI views the forecast as a prediction of customer counts which will be in effect during the next 5 years. Using an average would grossly understate the number of customers for the entire rate period.

b) What is the customer count for each class as of June 30, 2013?

HHI response: Please see table below.

	CUSTOMER COUNT
RES	4878
GEN<50KW	615
GEN>50KW	96
UNMETERED	5
SENTINEL LIGHTS	21
STREET LIGHTS	1
TOTAL	5616

c) At page 347 of the July PDF version HHI states: "The company shut down completely in the month of January (2009) and has resumed production in February with only of one out of three production lines". The Application subsequently states: "*The company permanently ceased it operation at the end of 2009*". Please confirm that it was February 2009 that the company resumed production and that it is currently permanently shut down.

HHI response: HHI confirms that it was in February 2009 when partial production was resumed and that they gradually terminated all of their operations at the end of that year. Furthermore, the building has also since then been demolished.

3.0 – VECC –13

Reference: Exhibit 3, Tab 1, Schedule 4
Load Forecast Worksheet, Input WS Regression Analysis Tab
2013 Ontario Budget
(http://www.fin.gov.on.ca/en/budget/ontariobudgets/2013/)

What is the basis for the employment level forecast used for 2013 and 2014?

HHI response: HHI used a 10 year average to determine the employment forecast for 2013 and 2014. As far as HHI knows, this is an acceptable method of projecting the bridge and test year levels. For employment levels, monthly full-time employment for the Ottawa Economic Region as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM) were used.

a) The employment levels forecast for 2013 and 2014 are lower than those for 2012. However, the 2013 Ontario Budget (Table 2.6) calls for provincial employment increases in 2013 and 2014 of 1.2% and 1.4% respectively. Please reconcile.

HHI response: HHI is of the opinion that it is very unlikely that the Ontario economic outlook would apply uniformly throughout the province. In fact the reality is that labour force and employment in the Ottawa region is in a downward trend as can be seen in the table below.

Labour force characteristics, seasonally adjusted, by census metropolitan area (3 month moving average)
(Ottawa-Gatineau (Ont.-Que.), Ottawa (Ont.)-Gatineau (Que.), Ontario part, Ottawa (Ont.)-Gatineau (Que.), Quebec part)

	Aug-13	Sep-13	August 2013 to September 2013	September 2012 to September 2013	August 2013 to September 2013	September 2012 to September 2013
	thousands		change (thousands)		% change	
Ottawa-Gatineau (Ont.-Que.)						
Population	1,067.50	**1,068.70**	1.2	14.7	0.1	1.4
Labour force	744.4	**742.1**	-2.3	-14.8	-0.3	-2
Employment	693.3	**693.9**	0.6	-13.9	0.1	-2
Unemployment	51.1	**48.2**	-2.9	-0.9	-5.7	-1.8
Unemployment rate (%)	6.9	**6.5**	-0.4	0	...	...
Participation rate (%)	69.7	**69.4**	-0.3	-2.4	...	...
Employment rate (%)	64.9	**64.9**	0	-2.3	...	...
Ottawa (Ont.)-Gatineau (Que.), Quebec part						
Population	265.7	**266**	0.3	3.2	0.1	1.2
Labour force	179.2	**178.3**	-0.9	-4.3	-0.5	-2.4
Employment	168.4	**167.7**	-0.7	-3.7	-0.4	-2.2
Unemployment	10.8	**10.6**	-0.2	-0.6	-1.9	-5.4
Unemployment rate (%)	6	**5.9**	-0.1	-0.2	...	...
Participation rate (%)	67.4	**67**	-0.4	-2.5	...	...
Employment rate (%)	63.4	**63**	-0.4	-2.2	...	...
Ottawa (Ont.)-Gatineau (Que.), Ontario part						
Population	801.8	**802.8**	1	11.6	0.1	1.5
Labour force	565.2	**563.8**	-1.4	-10.5	-0.2	-1.8
Employment	524.9	**526.2**	1.3	-10.2	0.2	-1.9
Unemployment	40.3	**37.6**	-2.7	-0.2	-6.7	-0.5
Unemployment rate (%)	7.1	**6.7**	-0.4	0.1	...	...
Participation rate (%)	70.5	**70.2**	-0.3	-2.4	...	...
Employment rate (%)	65.5	**65.5**	0	-2.3	...	...

Note: Population 15 and over.

Sources: Statistics Canada, CANSIM, table 282-0116 and Catalogue no. 71-001-XIE.

Last modified: 2013-10-11.

3.0-VECC – 14

Reference: Exhibit 3, Tab 1, Schedule 4, Table 13
Staff Interrogatory 3.0-Staff-12

Preamble: Immediately after Table 16, HHI states: "An increase in inhabitants usually results in an increase in commercial or municipal services"

a) Please re-do the regression analysis, excluding the employment variable but including residential customer count by month as an explanatory variable. Please provide the resulting regression statistics and the purchase power forecast for 2013 and 2014.

HHI response: Please note that historical customer count by month is not available for year prior to 2013. HHI therefore used a year customer count to present the scenario requested. The regression results are presented below. Details can be found in the model filed in conjunction with these responses. (see yellow tabs for this specific scenario)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.92529
R Square	0.856161
Adjusted R Square	0.850575
Standard Error	744594.7
Observations	108

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	3.4E+14	8.5E+13	153.2693	1.93E-42
Residual	103	5.71E+13	5.54E+11		
Total	107	3.97E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	16906697	3508589	4.81866	4.99E-06	9948239	23865155	9948239	23865155
HDD	6147.726	348.2184	17.6548	6.36E-33	5457.116	6838.335	5457.116	6838.335
CDD	8238.396	2876.124	2.864409	0.005064	2534.282	13942.51	2534.282	13942.51
Spring Fall	-704157	170577.5	-4.12807	7.44E-05	-1042457	-365856	-1042457	-365856
ResCustCount	-1121.71	740.8125	-1.51416	0.133049	-2590.93	347.5205	-2590.93	347.5205

3.0-VECC – 15

Reference: Exhibit 3, Tab 1, Schedule 4

a) Please explain how the weather adjusted purchases set out in Table 14 were derived.

HHI response: HHI applied the regression results (coefficient of Intercept, HDD, CDD, Spring Fall Flag and Full Time Employment for Ottawa Region) to come up with an adjusted purchased kWh. The calculations and formulas can be found in tab ***Input WS Regression Analysis*** in the excel version of Load Forecast Model which was originally filed in conjunction with the application.

b) The paragraph preceding Table 14 states: “HHI has also provided a 2013 forecast assuming twenty-year normal weather conditions”. Please indicate where in the Application this information is provided and whether HHI has also provided a 2014 forecast based on 20-year normal weather conditions. If either the 2013 or 2014 forecasts based on 20-year normal weather conditions have not been provided, please do so.

HHI response: The 10 year vs 20 year forecast is presented at the next page. The Load Forecast filed in conjunction with the model depicts the regression results using the 20 year average instead of the 10 year average. Please note that the various scenarios presented in the model are hypothetical and for illustrative purposes only.

Retail by Class

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 year avg	20 year avg	as filed (9 years)
HDD	629.80	1115.90	773.90	920.10	923.00	801.60	875.40	875.30	848.20	709.40	977.30	1045.30	920.70	733.50	797.10	754.20	979.50	789.20	893.20	831.00	872.10	859.68	860.41
Jan	791.30	833.40	796.20	783.30	736.40	609.80	670.90	728.20	746.80	668.80	841.50	750.00	700.60	720.90	820.00	774.30	711.50	655.80	729.00	671.40	737.50	737.01	725.94
Feb	604.40	637.50	537.00	656.20	678.30	575.80	645.70	502.30	652.30	651.70	675.00	559.20	668.80	600.40	643.00	721.10	598.30	460.70	636.00	460.30	602.28	608.20	594.20
Mar	320.30	375.70	434.90	418.40	378.60	285.90	336.80	391.00	338.10	358.80	424.60	377.80	324.80	321.60	361.10	299.60	334.30	258.10	347.40	363.30	341.26	352.56	332.00
Apr	136.10	188.40	148.00	187.90	240.50	43.60	83.30	152.00	109.60	227.60	154.10	166.20	205.00	128.20	157.30	185.40	181.60	112.30	142.80	96.00	152.89	152.30	152.76
May	48.70	35.40	19.00	20.90	11.70	43.40	20.30	63.20	25.50	61.70	38.90	54.00	16.10	27.60	34.20	22.40	50.40	37.60	18.50	0.00	29.97	32.48	28.98
Jun	0.00	0.80	6.80	1.60	10.50	3.40	3.80	12.20	21.60	5.30	2.00	1.80	2.90	0.30	11.80	0.30	13.10	4.50	0.00	0.00	3.67	5.14	3.86
Jul	6.40	33.60	9.30	13.70	14.30	7.70	14.80	18.30	4.70	6.80	13.30	29.80	8.40	18.20	20.10	14.40	26.10	14.70	2.30	8.40	15.57	14.27	15.82
Aug	151.50	100.10	159.30	83.80	120.60	81.90	65.80	138.10	89.90	56.90	60.40	66.80	59.20	121.00	76.00	95.40	106.50	112.00	55.40	127.30	88.00	96.40	91.07
Sep	342.20	277.50	237.50	314.20	334.20	270.70	321.50	290.80	266.00	370.00	336.60	287.00	269.70	335.70	227.50	321.80	355.50	311.00	259.10	243.10	294.70	298.58	290.04
Oct	417.80	432.60	611.80	575.20	552.70	452.70	406.70	489.40	410.10	535.20	468.80	484.30	484.20	417.30	517.00	502.80	417.40	491.60	392.90	541.70	471.80	480.11	472.13
Nov	573.90	696.40	850.90	634.70	754.90	648.40	691.80	882.60	602.20	728.30	722.20	814.90	762.00	610.00	787.70	796.70	759.40	731.40	415.00	680.60	707.99	707.20	706.41
Dec																							

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 year avg	20 year avg	as filed (9 years)
CDD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Jan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Feb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.30	0.00	1.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.20	0.51	0.77	0.57
Apr	6.90	8.80	5.70	8.00	0.00	28.60	31.30	2.80	13.70	6.50	0.10	4.00	1.90	16.90	0.00	0.00	2.50	1.60	16.70	21.00	6.47	8.85	7.18
May	29.90	71.70	86.30	51.90	78.70	77.90	99.60	30.70	75.90	39.50	54.80	27.10	111.60	48.20	17.30	0.00	3.20	38.20	59.10	70.40	42.99	53.60	41.68
Jun	112.60	106.00	125.90	67.70	95.80	89.20	141.70	58.60	78.40	121.00	90.10	86.50	128.60	130.60	66.90	60.50	44.90	33.40	137.50	142.20	92.12	95.91	92.34
Jul	98.40	39.90	78.90	78.70	41.30	86.10	57.60	60.10	127.50	106.50	106.20	47.50	115.40	68.10	65.10	78.90	42.90	150.80	82.30	97.60	85.48	81.49	83.18
Aug	10.70	2.30	5.10	33.80	4.40	12.20	49.60	13.70	25.90	51.40	23.70	11.10	33.10	5.30	79.30	49.50	82.10	93.00	32.90	20.60	43.06	31.99	45.21
Sep	0.00	0.00	1.30	0.00	0.00	0.00	0.00	0.00	0.00	4.10	0.00	0.00	6.40	0.00	25.70	25.00	5.00	26.20	1.40	0.00	8.97	4.76	9.97
Oct	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.90	0.00	0.00	0.00	0.00	0.00	0.19	0.10	0.21
Nov	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 – VECC –16

Reference: Exhibit 3, Tab 1, Schedule 4, Tables 19 and 20

a) Adjustments were made to the Residential and GS<50 consumption forecasts for 2013 and 2014 to account for new customers but no similar adjustment was made to the GS>50 consumption forecasts. Please explain why.

HHI response: Based on the information known by the executives at HHI at the time of the application, the utility did not feel the need to further adjust the results of the Load Forecast and was in agreement with the addition of 2 GS>50 customers in 2013 and 2 additions in 2014. One of the main advantages of being a smaller utility is that it allows HHI to be well informed on new general service customers.

3.0 – VECC –17

Reference: Exhibit 3, Tab 1, Schedule 5
Staff Interrogatory 3.0-Staff-15

Preamble: The Board's Filing Guidelines issued July 2013 (Chapter 2, pages 24-25) state:
Further, the actual results for 2011 and 2012 historical years, which will, in all likelihood, be used to develop the base forecast, includes the impacts of 2011 and 2012 CDM programs. The CDM adjustment to the load forecast should also take into account the historical CDM results factored into the base load forecast before the CDM adjustment, in order to avoid double counting of the impacts. ".

a) With respect to Table 24, the total percentages reported for the rows and columns do not reconcile with the sums of the individual entries. Please reconcile and correct.

HHI response: Please find below the corrected table

Revised

		4 Year (2011-2014) kWh Target: 9,280,000			
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	7.73%	7.73%	7.73%	7.73%	30.94%
2012 CDM Programs		7.38%	7.38%	7.38%	22.15%
2013 CDM Programs			15.64%	15.64%	31.27%
2014 CDM Programs				15.64%	15.64%
Total in Year	**7.73%**	**15.12%**	**30.76%**	**46.39%**	**100.00%**
		kWh			
2011 CDM Programs	717,718.00	717,718.00	717,718.00	717,718.00	2,870,872.00
2012 CDM Programs		685,247.00	685,247.00	685,247.00	2,055,741.00
2013 CDM Programs			1,451,129.00	1,451,129.00	2,902,258.00
2014 CDM Programs				1,451,129.00	1,451,129.00
Total in Year	**717,718.00**	**1,402,965.00**	**2,854,094.00**	**4,305,223.00**	**9,280,000.00**

b) With respect to Tables 24 and 25 the 430,000 kWh reported in Table 24 as the annual savings from 2012 CDM programs does not reconcile with the total CDM savings from 2012 programs of 490,000 kWh shown in Table 25 (i.e. 0.19+0.19+0.03+0.06). Please reconcile this difference and correct the tables in the Application as necessary.

HHI response: See table above.

c) Please confirm that HHI's proposed 6,782,178 kWh adjustment for CDM includes 2,011,585 kWh associated with CDM savings achieved in 2011 and 2012.

HHI response: VECC's statement is correct.

d) In accordance with the Board's Guidelines, please confirm that these savings should be removed as part of the "manual adjustment" since they are already reflected in the actual purchased power values used to develop the initial load forecast.

HHI response: For the purpose of calculating the CDM adjustment, HHI used the table which was unofficially circulated by the OEB in advance of the application deadline. HHI agrees to update the table and adjustment in accordance with a revised Board approved process or a decision stating so.

e) In its Decision regarding Wellington Hydro's 2013 rates the Board rejected the use of a net-to-gross adjustment factor and required that the CDM adjustment be done on a "net" basis. The Board also directed that the impact in the first year of a CDM program be adjusted using the "half-year rule". If not already done in response to Staff-15:

- Please recalculate the manual adjustment for 2014 so as to exclude the impact of 2011 and 2012 CDM programs and so as to be consistent with the Board's direction in the Centre Wellington Decision.

  HHI response: HHI notes that past precedents are often used to shape Board policies, however, if the Board had adopted this methodology as a policy, the July filing requirements would have stated as much. In the interest of providing a response to VECC's request, the scenario is presented below.
  HHI would like to make it clear that it does not consider a former Decision an obligation or commitment to update its evidence. As mentioned in the response to e) HHI commits to updating this information upon a Board Decision instructing the utility to do so.

3.0 – VECC –18

Reference: Exhibit 3, Tab 2, Schedule 2, Table 29
Cost Allocation Model, Sheet I6.1

a) Please reconcile the 2014 revenue at current rates reported in Table 29 ($1,329,732) with that reported in the Cost Allocation Model Sheet I6.1 ($1,443,257).

HHI response: The transformer allowance was inadvertently omitted from the Cost Allocation model. The model filed in conjunction with these responses has been rectified

b) Please also reconcile these values with the Distribution Revenue at Current Rates reported in the Revenue Requirement Workform (Exhibit 6, Tab 2 Schedule 2).

HHI response: This discrepancy is due to the error in the revenue deficiency used in both the RRWF and Cost Allocation model. Both models filed with this response have been corrected.

3.0 – VECC –19

Reference: Exhibit 3

a) Please confirm what changes, if any, HHI is proposing to its 2014 load forecast based on its responses to both Board Staff's and VECC's interrogatories and provide a schedule setting out the revised proposed load forecast (customer count, kWh and kW (where applicable) by customer class) and the supporting Load Forecast Worksheet.

HHI response:

Response: In compliance with page 69 of the RRFE report (published on October 18, 2012) which state;

"For distributors scheduled to rebase for 2014 and planning to seek the Board's approval for January 1 rates, there will be two options available:

> *1) Rebase under 3rd Generation IR filing requirements (in other words, without the 5 year capital plan) and remain under IR for 4 years total (rebasing plus 3 years) with rates adjusted annually using the 4th generation IR annual Adjustment"*

2) Delay rebasing by one year - rebase for January 1, 2015 rates, in which case the application will be filed using the Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements, and the total term will be 5 years.

By filing in April of 2013, HHI essentially adopted Option 1) which was to file its application under 3rd generation IRs filing requirement. HHI would like to make it clear that scenarios prepared as responses to VECC's IRs do not in any way imply a commitment on HHI's part to adopt these changes.

Unless specifically directed by the OEB in its decision and order, the utility is not proposing or committing to updating any of its Load Forecast information to reflect requirements that were issued on July 17 of 2013 – 2 months after HHI's application was filed.

HHI wishes to comply with Board policy and as such maintains that it has complied with Board policy on all aspects of the 3rd generation IRs filing requirements. It is HHI's understanding that it was the OEB who introduced the net-to-gross adjustment

3.0 – VECC –20

Reference: Exhibit 3, Tab 3, Schedule 2

a) Please confirm where the revenues received from SSS Admin charges are included in Appendix 2-F and what the values are for 2012, 2013 and 2014.

HHI response: Revenues from the SSS charges are included in account 4080 as can be seen in the table below.

Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual²	2012 Actual²	Bridge Year³ 2013	Bridge Year³ 2013	Test Year 2014
	Reporting Basis					CGAAP	MIFRS	CGAAP
4080	Distribution Services Revenue	-$14,391.11	-$14,502.22	-$15,392.81		-$15,400.00		-$15,400.00

b) Does the 2014 forecast of Interest and Dividend Income (Account 4405) include carrying charges in RSVA accounts? If so, please confirm that this should be excluded.

HHI response: HHI confirms that it does. HHI fails to understand why it should be excluded since there is an estimated RSVA carrying charges expense as well.

3.0 – VECC –21

Reference: Exhibit 3, Tab 3, Schedule 5

a) What is the impact on HHI's Other Revenues of the four proposed changes in Specific Service Charges for 2014?

HHI response:

CHANGE OF OCCUPANCY CHARGE	$ 9,760
Disconnect/Reconnect at meterafter regular hours	$ 80
Install / remove load control device after regular hours	$ 40
Service call after regular hours	$ 400
	$ 10,280

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EXHIBIT 4 – OPERATING COSTS

4.0-Staff-16

Ref: Exhibit 4/ Tab 2/ Schedule 2 – Employee Compensation

In Appendix 2-K, the employee costs for 2013 indicates an 8.0% increase and a further 2.6% increase in 2014.

a) Please provide the reason(s) for these increases.

HHI response: Management salaries are decided by HHI's Board of Directors and are entirely out of the utility's control. HHI has reviewed and compared its salaries with those of other utilities and has found that they are close to 40% less than those of its peers in the industry. HHI's management requested a salary adjustment of 8% to reduce the gap to approximately 32% and to be more in line with other managers and CFOs in the business.

In 2014 the decrease from 8% to 2.6% is explained by a lineman retiring therefore causing a salary reduction.

b) Please also provide the information that HHI used in determining the appropriate salaries.

HHI response: HHI used the "Mearie Group 2011/2012 Management Salary Survey of Ontario's Local Distribution Companies" to determine averages and medians with its equivalent in the industry. We made our evaluations based on the following categories:

. According to the number of customers – 1 to 10,000 customers
. According to gross income of less than 20 millions
. According to our District
. According to the number of employees (1 to 20 employees)

4.0-Staff-17

Ref: Exhibit 4/ Tab 1/ Schedule 4 – Bad Debt Expense

HHI explains that the Bad Debt expense is estimated to increase to a level of about $20,000 for 2013 based on updated requirements in the Distribution System Code. It further estimates an incremental increase of $10,000 to $30,000 in 2014 for the same reason. Please explain the reason for an increase of $20,000 for 2013 and a further $10,000 increase in bad debt expense for 2014 due to the DSC requirements.

HHI response: Since the introduction of the Low-Income Energy Assistance Program (LEAP) and the new customer service rules, LDC's have a lot of guidelines to follow and are very restricted when it comes to collecting deposits and disconnecting for non-payment. The disconnection process is very extensive and the rules force us to give customer payment plans to pay out debts while continuing service. By the time LDC's can act and disconnect service, the amount due is very high and customers choose to leave without paying. HHI has a large customer base of low-income customers and this result in a very difficult collection process.

The projections were established using monthly and yearly "aged arrears" reports. HHI exhaustively studied these reports and based on the knowledge we have of our customers and the report results, we determined an estimated bad debt expense. One of the advantages of being a small utility is that we know our customer base thoroughly.

4.0-Staff-18

Ref: Exhibit 4/ Tab 1/ Schedule 8/ Table 13 – Regulatory Costs

HHI documents an amount of $65,400 in regulatory costs for the test year and has provided a table (Table 13) showing a breakdown of the different types of services required. Please identify the services that Deloitte provided for the amounts documented.

HHI response: Deloitte is retained for the PIL's section of HHI's COS or IRM applications and is responsible for providing all income tax information. All interrogatories on the topic of PILs or income tax section are forwarded to them for responses. During the rate processes HHI consults them for data confirmation, precision, an opinion or direction of miscellaneous matters. Our consultant (Tandem) also use them from time to time for various information or clarification to establish revenue requirement.

4.0-Staff-19

Ref: Exhibit 4/ Tab 1/ Schedule 9 - Low Income Energy Assistance Program (LEAP)

Please state whether or not HHI has included an amount in its 2014 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

HHI response: HHI has included $2,000 of expense for the Low Income Assistance Program (LEAP) under Deductions Donation Expense (USoA #6205). This amount is based on the Board's determination that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000 should be included in the utility's costs.

HHI has a policy in place that it does not donate to charities and as such, we confirm that no charitable donations or payments for legacy programs have been included in OM&A expenses for 2014 other than the $2,000 for LEAP funding.

4.0-Staff-20

Ref: Exhibit 4/ Tab 7/ Schedule 2/ Page 60 – LRAMVA
Hydro Hawkesbury 2011 Final Annual OPA CDM Data

HHI has provided two tables that show the allocation of final net CDM program savings (kWh and kW) for both 2011 and 2012.

a) Please reconcile the total 2011 net energy savings (kWh) shown in your application (720,000 kWh) with the total 2011 net energy savings (kWh) in the Final OPA Report (717,718 kWh). Please provide a table that shows what programs HHI has included under each rate class.

HHI response: HHI used the summary information provided as part of the report to calculate its LRAMVA. HHI has since then updated the calculations to reflect the actual kWh. Please see the revised Appendices for further information.

b) Please reconcile the total 2011 net peak demand savings (kW) shown in your application (150.00 kW) with the total 2011 net peak demand savings (kW) in the Final OPA Report (149 kW). Please also provide a table that shows what programs HHI has included under each rate class.

HHI response: HHI used the summary information provided as part of the report to calculate LRAMVA. HHI has updated the calculations to reflect the actual kW.

c) Please discuss the reasonableness of requesting approval of the 2011 persisting savings in 2012 at this time, prior to the 2012 Final OPA Results being published.

HHI response: HHI anticipated that the 2012 final report would be released during the second quarter of the year. HHI used the projected savings published by the OPA in advance of the final 2012 report.

d) Please discuss if HHI will be updating its application to include a request for approval of its 2012 LRAMVA amounts related to its 2012 OPA Province-Wide CDM Programs. If HHI plans on updating its application, please discuss when it will do so.

HHI response: Now that the 2012 final report has been published, HHI can use the final savings to calculate its LRAMVA.

4.0-Staff-21

Ref: Exhibit 4/ Tab 7/ Schedule 2/ Page 59- 60 – LRAMVA

HHI noted in the fifth paragraph on page 59 that it is not requesting carrying charges on its LRAM amount. Later, in the first paragraph on page 60, HHI noted that it is seeking to recover carrying charges on its LRAM amount up until December 31, 2013.

a) Please reconcile these statements regarding carrying charges.

   HHI response: At the time of the revision, HHI was not sure whether is was allowed to apply carrying charges to the 2012 year end balance. HHI confirms that it is in fact requesting recovery of carrying charges.

b) If HHI is seeking approval of carrying charges at this time, please provide the carrying charges calculations and update the LRAMVA amount and rate riders accordingly.

   HHI response: The carrying charges on the LRAM are in the amount of $76.27. The LRAMVA and rate riders have been adjusted accordingly.

4.0-Staff-22

Ref: Exhibit 4/ Tab 7/ Schedule 2/ Page 61 – LRAMVA Rate Rider Table
Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13.5 and Appendix B

HHI indicates it has entered its total requested LRAMVA amounts, both for 2011 savings and persisting 2011 program savings in 2012, into Account 1576.

Section 13.5 of the CDM Guidelines notes that the Board has established Account 1568 as the LRAM variance account. It further notes that accounting guidelines regarding the LRAMVA can be found at Appendix B to the Guidelines.

a) Please explain why HHI should use account 1576 for the subject amounts. If this is an error, please confirm and correct when re-filing the continuity schedule. Please provide an updated LRAMVA Rate Rider Table.

HHI response: This was due to a typing error, as indicated in the EDVVAR model filed on June 12, 2013 as well as the revised model filed in conjunction with these responses, the account used to record the LRAMVA is in fact 1568.

b) Please provide a scenario where the LRAMVA Rate Rider table only includes LRAMVA amounts for 2011 program savings in 2011 and does not include any 2011 persisting savings in 2012.

HHI response: The first table below shows the 2011 savings only, while the second table shows the 2011 savings without persistence in 2012 and the 2012 savings.

	2011	2012	2013	
LRAM Claim (kW):	149			tab 3.1.1 of Final 2011 OPA report
LRAM Claim (kWh):	717,718			tab 3.1.1 of Final 2011 OPA report

Per class allocation (kWh)	2011 Alloc by Class	2012 Alloc by Class	2011 LRAM (kWh)	2012 LRAM (kWh)	Total
Residential	**33.27%**	**34.27%**	238,754.39	-	238,754.39
General Service < 50 kW	**11.98%**	**12.42%**	85,947.21	-	85,947.21
General Service > 50 to 4999 kW	**53.68%**	**52.19%**	385,277.94	-	385,277.94
Unmetered Scattered Load	**0.14%**	**0.14%**	1,002.54	-	1,002.54
Sentinel Lighting	**0.07%**	**0.07%**	479.11	-	479.11
Street Lighting	**0.87%**	**0.91%**	6,256.82	-	6,256.82
	100%	**100%**	**717,718**	**-**	**717,718**

Per class allocation (kW)	2011 Alloc by Class	2012 Alloc by Class	kW	kW	Total
General Service > 50 to 4999 kW	**98.14%**	**98.09%**	146.23	0.00	146.23
Sentinel Lighting	**0.13%**	**0.13%**	0.19	0.00	0.19
Street Lighting	**1.73%**	**1.78%**	2.57	0.00	2.57
			2.57	**0.00**	**149.00**

LRAMVA Rate Rider	2011 Volumetric Rate	2012 Volumetric Rate	2011 LRAM	2012 LRAM	Entry to 1568
Residential	0.0079	0.0080	$1,886.16	$0.00	$1,886.16
General Service < 50 kW	0.0054	0.0055	$464.11	$0.00	$464.11
General Service > 50 to 4999 kW	1.5288	1.5453	$223.56	$0.00	$223.56
Unmetered Scattered Load	0.0021	0.0021	$2.11	$0.00	$2.11
Sentinel Lighting	3.1724	3.2067	$0.61	$0.00	$0.61
Street Lighting	6.6567	6.7286	$17.13	$0.00	$17.13
			$2,593.68	**$0.00**	**$2,593.68**

	2011	2012	2013	
LRAM Claim (kW):	149	150		tab 3.1.1 of Final 2011 OPA report
LRAM Claim (kWh):	717,718	685,247		tab 3.1.1 of Final 2011 OPA report

Per class allocation (kWh)	**2011 Alloc by Class**	**2012 Alloc by Class**	**2011 LRAM (kWh)**	**2012 LRAM (kWh)**	**Total**
Residential	33.27%	34.27%	238,754.39	234,823.92	473,578.31
General Service < 50 kW	11.98%	12.42%	85,947.21	85,103.93	171,051.14
General Service > 50 to 4999 kW	53.68%	52.19%	385,277.94	357,635.51	742,913.45
Unmetered Scattered Load	0.14%	0.14%	1,002.54	986.92	1,989.46
Sentinel Lighting	0.07%	0.07%	479.11	470.05	949.16
Street Lighting	0.87%	0.91%	6,256.82	6,226.67	12,483.49
	100%	100%	717,718	685,247	1,402,965

Per class allocation (kW)	**2011 Alloc by Class**	**2012 Alloc by Class**	**kW**	**kW**	**Total**
General Service > 50 to 4999 kW	98.14%	98.09%	146.23	147.13	293.36
Sentinel Lighting	0.13%	0.13%	0.19	0.20	0.40
Street Lighting	1.73%	1.78%	2.57	2.67	5.24
			2.57	150.00	299.00

LRAMVA Rate Rider	**2011 Volumetric Rate**	**2012 Volumetric Rate**	**2011 LRAM**	**2012 LRAM**	**Entry to 1568**
Residential	0.0079	0.0080	$1,886.16	$1,878.59	$3,764.75
General Service < 50 kW	0.0054	0.0055	$464.11	$468.07	$932.19
General Service > 50 to 4999 kW	1.5288	1.5453	$223.56	$227.36	$450.92
Unmetered Scattered Load	0.0021	0.0021	$2.11	$2.07	$4.18
Sentinel Lighting	3.1724	3.2067	$0.61	$0.65	$1.26
Street Lighting	6.6567	6.7286	$17.13	$17.95	$35.08
			$2,593.68	**$2,594.70**	**$5,188.38**

4.0 - VECC- 22

Reference: Exhibit 4, Tab 1, Schedule 3/ Appendix 2-H OM&A Detailed

a) The Excel Spreadsheet column for 2010 appears to have reference errors. Please correct and re-file this table.

HHI response: Although HHI was unable to find the reference error in the original application, HHI attests that the Appendices filed along with these responses do not show a reference error in Appendix 2-H OM&A Detailed.

4.0 - VECC- 23

Reference: Exhibit 4, Tab 1, Schedule 3, Appendix 2-G

a) Please update the 2013 Bridge year OM&A budget to show (3 columns): original budget; year-to-date actuals and the remaining forecast to-year-end spending.

HHI response: Please see table below.

HAWKESBURY HYDRO INC.

2013 BUDGET

	GL ACCT NUMBER	DESCRIPTION	BUDGET 2013	ACTUALS 2013 AS OF SEPT 30	FORECAST (addition) TILL YEAR END	TOTTAL EXPECTED EXPENSES TILL YEAR END
		OPERATIONS & MAINTENANCE				
DISTRIBUTION EXPENSES	5014-000	Transfo Equipment - Operating Labour 115KV	$ 9,500.00	$ 3,394.00	$ 4,200.00	$ 7,594.00
(OPERATIONS)	5015-000	Transfo Equipment - Supplies 115 KV	$ 8,500.00	$ 3,662.00	$ 3,900.00	$ 7,562.00
	5016-000	Dist. Station Equipment - Operating Labour 44 KV	$ 10,000.00	$ 2,924.00	$ 5,000.00	$ 7,924.00
	5017-000	Dist. Station Equipment - Supplies	$ 5,000.00	$ 39,677.00	$ 350.00	$ 40,027.00
	5020-000	OH dist. Lines & Feeders- Labour	$ 11,500.00	$ 6,058.00	$ 4,950.00	$ 11,008.00
	5025-000	OH dist. Lines & Feeders- Supplies & expenses	$ 1,500.00	$ 1,345.00	$ 150.00	$ 1,495.00
	5035-000	OH dist. Transformers -Operations	$ 8,000.00	$ 4,209.00	$ 2,800.00	$ 7,009.00
	5040-000	UG dist. Line & Feeders- Labour	$ 2,100.00	$ 1,723.00	$ 300.00	$ 2,023.00
	5045-000	UG dist. Line & Feeders- Supplies & Expenses	$ 50.00	$ 415.98	$ 50.00	$ 465.98
	5055-000	UG dist. Transformers -Operations	$ 3,000.00	$ 1,014.00	$ 1,500.00	$ 2,514.00
	5065-000	Meter Expenses	$ 24,600.00	$ 6,383.00	$ 12,000.00	$ 18,383.00
	5095-000	OH Dist. Lines & Feeders - Rental paid	$ 1,500.00	$ 886.91	$ 325.00	$ 1,211.91
		SUB TOTAL (OPERATIONS)	**$ 85,250.00**	**$ 71,691.89**	**$ 35,525.00**	**$ 107,216.89**
DISTRIBUTION EXPENSES	5105-000	Supervision & Eng.	$ 1,000.00	$ -	$ 500.00	$ 500.00
(MAINTENANCE)	5120-000	Poles, Tow ers & Fixtures	$ 10,000.00	$ 17,267.00	$ 750.00	$ 18,017.00
	5125-000	OH Conductors	$ 34,000.00	$ 13,986.00	$ 14,000.00	$ 27,986.00
	5130-000	OH Services	$ 46,000.00	$ 5,645.00	$ 32,500.00	$ 38,145.00
	5135-000	Right of Ways	$ 65,000.00	$ 19,493.00	$ 38,000.00	$ 57,493.00
	5145-000	UG Conduit	$ 1,500.00	$ 289.00	$ 200.00	$ 489.00
	5150-000	UG Conductors & Devices	$ 8,900.00	$ 5,791.24	$ 2,200.00	$ 7,991.24
	5155-000	UG Services	$ 8,500.00	$ 5,385.00	$ 2,120.00	$ 7,505.00
	5160-000	Line Transformers	$ 13,000.00	$ 7,657.00	$ 3,350.00	$ 11,007.00
	5175-000	Meters	$ 1,800.00	$ 220.24	$ 800.00	$ 1,020.24
		SUB TOTAL (MAINTENANCE)	**$ 189,700.00**	**$ 75,733.48**	**$ 94,420.00**	**$ 170,153.48**
		TOTAL DIST. & TRANSFORMATION	**$274,950**	**$147,425**	**$129,945**	**$277,370**
BILLING & COLLECTING	5310-000	Meter Reading Expense	$ 38,000.00	$ 26,417.81	$ 11,600.00	$ 38,017.81
	5315-000	Customer Billing	$ 230,000.00	$ 183,656.00	$ 56,350.00	$ 240,006.00
	5320-001	Collecting	$ 102,130.00	$ 58,958.00	$ 56,050.00	$ 115,008.00
	5320-002	Collection Charges -Other Parties	$ 60.00	$ -	$ -	$ -
	5325-000	Collection-cash over and short				$ -
	5330-000	Collection Charges				$ -
	5335-000	Bad Bedts Expenses (Write-offs)	$ 20,000.00	$ (744.99)	$ 20,750.00	$ 20,005.01
	5340-000	Misc. Customer Account Expenses				$ -
		SUB TOTAL (B & C)	**$ 390,190.00**	**$ 268,286.82**	**$ 144,750.00**	**$ 413,036.82**
COMMUNITY RELATIONS	5410-000	Community Relations- Sundry	200	125	**$ -**	$ 125.00
	5415-000	Energy Conservation (DSM)		0		$ -
	5420-000	Community Safety Programs		0		$ -
		SUB TOTAL (COMMUNITY RELATIONS)	**$ 200.00**	**$ 125.00**	**$ -**	**$ 125.00**
ADMINISTRATION AND GENERAL EXPENSES.	5605-000	Executives Salary & Expenses (Director/Manager)	$ 109,000.00	$ 72,180.00	$ 43,000.00	$ 115,180.00
	5610-000	Management Salaries & Expenses(Ass. Manager)	$ 76,000.00	$ 51,902.00	$ 30,000.00	$ 81,902.00
	5620-000	Office Supplies & Expenses	$ 27,000.00	$ 15,776.00	$ 6,250.00	$ 22,026.00
	5630-000	Outside Service Employed	$ 19,850.00	$ 13,258.75	$ 3,750.00	$ 17,008.75
	5635-000	Property Insurance	$ 7,700.00	$ 2,927.00	$ 4,775.00	$ 7,702.00
	5640-000	Injuries & Damages	$ 7,700.00	$ 5,774.00	$ 2,000.00	$ 7,774.00
	5645-000	Employee Pensions & Benefits	$ 3,750.00	$ 2,647.00	$ 1,120.00	$ 3,767.00
	5655-000	Regulatory Expenses	$ 138,000.00	$ 9,993.19	$ 60,000.00	$ 69,993.19
	5665-000	Misc General Expenses	$ 15,100.00	$ 12,440.00	$ 2,575.00	$ 15,015.00
	5675-000	Maintenance of General Plant	$ 56,200.00	$ 38,146.00	$ 12,000.00	$ 50,146.00
	5680-000	Electrical Safety Authority Fees (ESA)	$ 5,100.00	$ 4,962.51	$ 150.00	$ 5,112.51
	5685-000	IMO Fees and Penalties				$ -
	5705-000	Amortization Expenses	$ 202,997.00	$ 158,734.00	$ 44,263.00	$ 202,997.00
		SUB TOTAL ADMIN & GEN EXPENSES	**$ 668,397.00**	**$ 388,740.45**	**$ 209,883.00**	**$ 598,623.45**
INTEREST EXPENSES	6005-000	Interest on Long Term Debt	$ 57,800.00	$ 21,721.00	$ 36,079.00	$ 57,800.00
	6035-000	Other Interest Expenses	$ 37,944.00	$ 20,744.00	$ 17,250.00	$ 37,994.00
		SUB TOTAL (INTEREST EXPENSES)	**$ 95,744.00**	**$ 42,465.00**	**$ 53,329.00**	**$ 95,794.00**
		OPERATIONS & MAINTENANCE	**$ 1,429,481.00**	**$ 847,042.64**	**$ 537,907.00**	**$ 1,384,949.64**

4.0 - VECC- 24

Reference: Exhibit 4, Tab 1 (E4.T1.S1)

a) Table 2b) appears to show the incremental on-going costs of smart meter operations is $96,921. This amount includes to charges from Utilismart and amounts for manual reads. Please explain these two charges and confirm the on-going costs for the operation of smart meters in 2014 and beyond.

HHI response: HHI utilizes its internal staff to perform manual reads for its General>50kW customers that do not have smart meters installed at their premise. HHI is progressively changing them for smart meters when necessary or once the seal is expired. It is done gradually since smart meters are not mandatory for that customer class.

HHI does not expect many cost variations for smart meters for 2014 and beyond. The estimated costs of $92,921 are to our knowledge the best estimate.

Table 2b) Smart Meter Related On-Going Costs

DESCRIPTION	Acct 5065 Meter Expense	Acct 5175 Maintenance of Meters	Acct 5310 Meter Reading Expense	Acct 5315 Billing Expense	Total
HHI internal labour - Meter testing, change, repairs	$9,000.00				
Meter re-verification, antenna, adapters…		$1,200.00			
Bell Canada - Collector Fees			$2,676.00		
Utility (HHI) - Collector Invoice			$204.00		
ASP Hosting				$17,568.00	
AS2 Hosting				$2,224.80	
EIS Maintenance				$1,671.00	
Bill Archival Fees				$3,182.64	
E-Care Maintenance & Hosting				$1,591.32	
HHI internal labour - Manual Reads			$7,152.00		
Utilismart			$26,292.00	$20,160.00	
YEARLY COSTS - TOTAL	**$9,000.00**	**$1,200.00**	**$36,324.00**	**$46,397.76**	**$92,921**

4.0 - VECC- 25

Reference: Exhibit 4, Tab 1 (E4.T1.S4), Appendix 2-G

a) Account 5335. Please explain how the 2014 Bad Debt expense ($30k) was calculated.

HHI response: Please refer to Board 4.0-Staff-17.

b) Please provide the 2013 Bad Debt expense to-date.

HHI response: HHI assesses and evaluates its aged arrears report thoroughly at the end of the year to establish its bad debt expense. As of September 30, 2013, the uncollected accounts for finalized customers were in the amount of $58,276.77.

4.0 - VECC- 26

Reference: Exhibit 4, Tab 1 (E4.T1.S4), Appendix 2-G

a) Account 5065. HHI states that Meter Expenses increases are due to the installation of smart meters. Please explain why HHI does not anticipate the costs captured in this account declining now that the initial installation of smart meters has been completed.

HHI response: HHI used the incremental budgeting approach (current year's budget becomes the basis for the next year's spending plan) for determining the meter expense account's future costs. HHI will continue to record labour costs to this account since they are still from time to time changing meters for greater than 50kW General customers. Also, this account is used for recording meter testing's, meter changes or repairs.

4.0 - VECC- 27

Reference: Exhibit 4, Tab 1

b) Account 5310. The evidence states that the cost associated with conversion to monthly billing was $10,500. Please clarify whether this was a one-time cost or an ongoing cost. If the former please provide the ongoing increase in costs in going from bimonthly to monthly billing.

HHI response: The meter reading expense before the installation of smart meters was approximately $1,750 per month. The Utilismart meter reading expense is $2,200 for the same period. The Utilismart fee is $450 more per month, which represents an increase of $5,400 annually. The difference of $15,324 is the extra annual cost HHI has to incur with the installation of smart meter for monthly billing.

Whether HHI bills monthly or bi-monthly, the meter reading costs remain the same since Utilismart reads are done on a daily basis.

	Before Smart Meter Installation	After Smart Meter Installation	Variance
Bell Canada - Collector Fees	-	2,676	
Utilitity - Collectore Invoice		204	
HHI internal labour - Manual Reads		7,152	
Outsourced person - Manual Reads	21,000		
Utilismart		26,292	
	21,000	**36,324**	**15,324**
Average Monthly Cost	1,750	3,027	

4.0 - VECC- 28

Reference: Exhibit 4, Tab 1

a) HHI notes that it forecasts an increase in property insurance premiums of $4,300. Does HHI purchase its insurance from the MEARIE Group? If yes please explain if HHI tenders for this product and if not how it satisfies itself that it is receiving a competitive rate.

HHI response: No, HHI is not insured with The MEARIE Group for its property insurance, and yes, HHI did tender to obtain the best competitive rate. The premium increased is explained by additional coverage for the additions in HHI's two (2) substations.

4.0 - VECC- 29

Reference: Exhibit 4, Tab 1

a) HHI states office supplies costs for 2014 increased due to the upgrade of the telephone service. Of the $3,000 increase noted in the evidence how much is due to this upgrade? Is this an ongoing or one-time cost?

HHI response: HHI's telephone system is outdated and HHI was informed by its service provider that in a near future, the maintenance service option will no longer be available. The full amount of $3,000 is for this upgrade and is a one-time cost.

4.0 - VECC- 30

Reference: Exhibit 4, Tab 1 (E4.T1.S5) Table 11a)

a) Please confirm the first row labeled "Number of Customers" shows customer numbers and not dollars as indicated by the format.

HHI response: The row labeled Number of Customers in fact shows the number of customer and not a dollar value.

b) For the most recent Board published year please provide the comparable Table 11a) OM&A per customers and Customers/FTEE for the following cohort utilities: Cooperative Hydro Embrun, Hydro 2000; Ottawa River Power Corporation; Renfrew Hydro Inc. Please comment on the comparability of these utilities to HHI.

Utility	HHI	HHI	Embrun	Renfrew	ORPC	Hydro 2000
Cost of Service Year	2014	2010	2010	2010	2010	2012
Number of customer	5690	5579	1956	4215	10633	1216
OM&A	$1,126,665.00	$1,021,189.00	$531,979.00	$1,202,039.00	$2,673,386.00	$425,428.00
OM&A per customer	$198.01	$183.04	$271.97	$285.18	$251.42	$349.86
Number of FTE	8	8	3	10	28	3
Customer/FTE	711.25	697.38	652.00	421.50	379.75	405.33
OM&A Cost/FTE	$140,833.13	$127,648.63	$177,326.33	$120,203.90	$95,478.07	$141,809.33

HHI response: The numbers speak for themselves… The average OM&A/customer taken from the 2012 Yearbook amounts to $268.30. If HHI were to apply this average to its number of customer the resulting OM&A would total $1,526,627 or $399,962 higher than the requested OM&A.

4.0-VECC – 31

Reference: Exhibit 4, Tab 1 (E4.T1.S7)

a) Please show by account the amortization of the 2014 costs for the evaluation of the 10 MVA transformer (44KV). That is, explain how many years the cost is amortized over and show which account(s) contain these figures for 2014.

HHI response: All of the expenditures for substation 44KV are recorded in USoA account 1820 and are amortized over 45 years.

Appendix 2-B												
Fixed Asset Continuity Schedule - NewCGAAP												
				Year	2014							
			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
47	1820	Distribution Station Equip. <50 kV	$ 1,056,183	$ 60,000		$ 1,116,183	$ (142,005)	$ (27,195)		$ (169,200)	$ 946,983

4.0-VECC – 32

Reference: Exhibit 4, Tab 1 (E4.T1.S8)

a) Please provide a breakdown description of the $138,000 HHI is forecasting for 2013 regulatory costs.

HHI response:

OEB Annual Assessment	$8,600.00	
OEB Section 30 Costs (OEB-initiated)	$1,500.00	
Consultants' costs for regulatory matters	$106,500.25	
4th installment of 2010 COS amortized costs (Elenchus)		$59,202
Tandem Energy Services Inc.(as of Sept 2012)		$30,000
Deloitte		$15,000
IRM cost previously recorded in acct 1460		$1,964
OEB Hearing costs for Smart Meter application		$334
FEE FOR PUBLICATION OF APPLICATION IN LOCAL NEWSPAPERS	$1,400.00	
Intervenor costs	$20,000.00	
Sub-total - Ongoing Costs [3]	$138,000.25	
Sub-total - One-time Costs [4]	$0.00	

b) The 2014 forecast regulatory costs are $65,400. Table 13 (shown below) appears to show annual costs of $63,900. Please reconcile the difference.

OEB Assessment fee	$8,900/year
Intervener (2014COS)	$25,000 ($5,000 over 5 years)
Intervener (on-going)	$5,000/year (IRM etc.)
TESI (on-going)	$30,000/year
Deloitte (2014COS)	$25,000 ($5000 over 5 years)

Deloitte (on-going)	$10,000/year (IRM and other filings)

HHI response: The table above is missing $1,500 for OEB initiated cost award (OEB Section 30 Costs)

4.0-VECC – 33

Reference: Exhibit 4, Tab 1 (E4.T2.S1)

Preamble: HHI makes the following statement:

Revised June 12, 2013. HHI does not use specific benchmarking studies to determine salary ranges. However HHI and its shareholder are well aware of the salary ranges in neighbouring utilities and use the neighbouring salaries as a guideline. HHI is also aware of recently published surveys and attests that current salaries are well below those suggested salary range.

8% Salary Increase in 2013 & 2014 over 2012 for Management Salaries: Management intends to negotiate its salaries in 2013 & 2014 to be more in-line with its peers in the industry. Therefore, HHI augmented its salary expense of 8% in view of an accepted demand.

a) Please explain what is meant by the phrase "*in view of an accepted demand*".

HHI response: In this context, "demand" means "request". HHI meant that it requested 8% in hopes that the OEB will view this increase as reasonable and ultimately accept the request.

b) HHI's proposal gives management a 17% increase from 2012 to 2014, while unionized staff compensation increases by 6% during the same period. What evidence is HHI relying on to support the larger increase in management compensation levels.

HHI response: HHI's management salaries are close to 40% less than those of its peers in the industry. Management requested a salary adjustment to be more in line with other managers and CFOs in the business. HHI used the "Mearie Group 2011/2012 Management Salary Survey of Ontario's Local Distribution Companies" to determine averages and medians with its equivalent in the industry.

Unionized staff salaries are negotiated and accepted by them, therefore our budgeted expense is based on the negotiated amount outlined in their union contract. Furthermore, the retirement of a lineman in mid-2014 reduces the salary increase average.

4.0 - VECC- 34

Reference: Exhibit 4, Tab 1

a) Please provide association fees paid to the EDA for each of the years 2010 through 2014 (forecast).

HHI response: Please refer to the table below.

EDA MEMBERSHIP FEES	
YEAR	**AMOUNT**
2010	13,400
2011	13,850
2012	14,600
2013	15,300
EST 2014	16,000

b) Separately provide and describe the cost of all other association memberships.

HHI response: HHI does not pay membership dues except those of the EDA.

4.0 - VECC- 35

Reference: Exhibit 4, Tab 6 (E4.T6.S1)

a) Please provide the PILs payments made in each of the years 2009 through 2012

HHI response: HHI did not pay PILs during those four (4) years. Please refer to the table below.

PIL's PAID		
YEAR	PAYMENTS	RETURNS
2009	$ -	$ (59,829)
2010	$ -	$ (161,142)
2011	$ -	$ (214,220)
2012	$ -	$ -

EXHIBIT 5 – COST OF CAPITAL AND RATE OF RETURN

5.0-Staff-23

Ref: Exhibit 5/ Tab 2/Appendix 2-OB – Long-term Debt

a) Why does HHI document that all debt owed to the Town of Hawkesbury is "third party" debt rather than "affiliated" debt?

HHI response: HHI should have recorded "affiliated" debt rather than "third party". Revised appendices are being filed in conjunction with these responses.

b) Exhibit 5/Tab 2/Schedule 1/ Table 4 documents that the SUB 44kV loan for $741,098 is due to Infrastructure Ontario, while Appendix 2-OB documents that the lender is the Town of Hawkesbury. Please confirm the lender and whether the debt is third party or affiliated.

HHI response: The lender is Infrastructure Ontario and is a third party lender. Please find below the revised tables.

Year 2013

As of Dec. 31st

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	ACTUAL INTEREST EXPENSE
1	Convertible Promissory Note	Town of Hawkesbury	Affiliated	Fixed Rate	JANUARY 1, 2013	1	$ -	6.50%	$ -	$ 8,711.72
2	SUB 44KV Loan	Infrastructure Ontario	Third-Party	Fixed Rate	JANUARY 1, 2013	1	$ 722,761	3.94%	$ 28,476.79	$ 28,870.54
3	SUB 110KV Loan	Infrastructure Ontario	Third-Party	Fixed Rate	JULY 1, 2013	1	$ 1,483,000	3.94%	$ 29,215.10	$ 28,900.00
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							**$ 2,205,761**	**0.02616**	**$ 57,691.89**	**$ 66,482.26**

Year 2014

As of Dec. 31st

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	ACTUAL INTEREST EXPENSE
1	SUB 44KV Loan	Infrastructure Ontario	Third-Party	Fixed Rate	JANUARY 1, 2014	1	$ 703,688	3.94%	$ 27,725.32	$ 28,134.82
2	SUB 110KV Loan	Infrastructure Ontario	Third-Party	Fixed Rate	JANUARY 1, 2014	1	$ 1,449,000	3.94%	$ 57,090.60	$ 56,400.00
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							**$ 2,152,688**	**0.0394**	**$ 84,815.92**	**$ 84,534.82**

5.0 - VECC- 36

Reference: Exhibit 5, Tab 2

a) Please reconcile Table 4 (reproduced below) with Appendix 2-OB for 2013 and 2014.

Table 4 below summarizes HHI's debt position.

Debt Holder	Particulars	**Balance as of December 31 2012**
Town of Hawkesbury	Shareholder Note	$253,366
Infrastructure Ontario	Capital funding for the 44KV	$741,098
Total		$994,464

HHI response: As indicated in the table header, the above presents balances at December 31, 2012. Appendix 2-OB presents the same information under the table heading of **2012**.

5 – VECC –37

Reference: Exhibit 5, Tab 2

a) Please show the derivation of the 4.12% long-term debt rate shown in Appendix 2-OA. Specifically, reconcile this rate with the fixed rate loans of 3.94% shown in Appendix 2-OA.

HHI response: HHI used the prescribed cost of capital rates. For third party debt, HHI should have used the actual debt rate of 3.94%. HHI has updated it cost of capital to reflect the revised weighted average cost of capital instead of the Board prescribed cost of capital. The revised cost of capital is shown in the table below.

Appendix 2-OA

Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$3,975,751	3.94%	$156,645
2	Short-term Debt	4.00%	(1)	$283,982	2.07%	$5,878
3	**Total Debt**	60.0%		$4,259,733	3.82%	$162,523
	Equity					
4	Common Equity	40.00%		$2,839,822	8.98%	$255,016
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$2,839,822	8.98%	$255,016
7	**Total**	100.0%		$7,099,556	5.88%	$417,539

5-VECC- 38

Reference: Exhibit 5, Tab 2

a) For 2014 is HHI forecasting any debt to be held by:

HHI Response: Please see table below – APPENDIX 2-OB

(1) Infrastructure Ontario - if yes please show amount and rate

Appendix 2-OB
Debt Instruments
Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($) As of Dec. 31st	Rate (%) (Note 2)	Interest ($) (Note 1)	ACTUAL INTEREST EXPENSE
1	SUB 44KV Loan	Infrastructure Ontario	Third-Party	Fixed Rate	JANUARY 1, 2014	1	$ 703,688	3.94%	$ 27,725.32	$ 28,134.82
2	SUB 110KV Loan	Infrastructure Ontario	Third-Party	Fixed Rate	JANUARY 1, 2014	1	$ 1,449,000	3.94%	$ 57,090.60	$ 56,400.00
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 2,152,688	0.0394	$ 84,815.92	$ 84,534.82

(2) Town of Hawkesbury – if yes show amount and rate. n/a

(3) Any other party – if yes show amount and rate. n/a

b) Please answer same for all short-term debt.

For both a) and b) please indicate the date(s) of expected drawdown of the loan (e.g. if HHI expects to draw a portion of the loan in June 2014 indicate the date and amount).

HHI Response: HHI received drawdowns of $724,000 as of November 1, 2013, and expects the balance at the beginning of 2014 from Infrastructure Ontario.

EXHIBIT 7 – COST ALLOCATION

7.0-Staff-24

Ref: Exhibit 7/ Tab 1/Table 6 – Cost Allocation

In the above reference, HHI provides the calculations for the cost allocation of the revenue requirement. In Table 6 HHI provides the revenue and cost allocation for all the classes. Please provide detailed calculations to illustrate how the amounts and percentage under "Existing Rates" columns are calculated.

7.0-VECC – 39

Reference: Exhibit 7, Tab 1, Schedule 1

a) Please explain why service weighting factors are not applicable to the Street Lighting class.

HHI response: Weighting factors are not applicable because the town of Hawkesbury is responsible for the servicing of Street Lights.

b) The Application states that "HHI has deemed it appropriate to use the coincident and non-coincident peaks from the 2010 Application". Please confirm whether HHI used i) the actual data from the 2010 Application or ii) the coincident/non-coincident kW to kWh relationships for each class from the 2010 Application in establishing the demand data for the current application.

HHI response: HHI used the actual data from the 2010 Application which was updated to reflect the updated demand.

c) Please confirm that the demand data used in the 2010 Application was based on analysis done using 2004 data.

HHI response: Confirmed however the demand data was update to reflect the loss of the large user. All other classes have remained steady since the 2010 Cost of Service.

7.0-VECC – 40

Reference: Cost Allocation Model, Sheets I7.1 and I7.2

a) Please show that the smart meter capital costs as shown in Sheet I7.1 were derived from the smart meter costs by customer class reported in Exhibit 2.

HHI response: HHI has update sheet I7.1 to report information which now matches the gross balance of smart meters at end of 2014. The Revised information can be found in Appendix C of this document

b) Please explain why there are not meter reading weighting factors attributed to Residential or GS<50 in Sheet I7.2.

HHI response: HHI has update sheet I7.2 to report information which now reflect weighting factors attributed to Residential and GS <50. The Revised information can be found in Appendix C of this document

c) Please also explain how, despite the fact there are no meter reading weighting factors for these classes, they are assigned a portion of the meter reading expense as shown in Sheet O5.

HHI response: see response to b).

7.0-VECC – 41

Reference: Cost Allocation Model, Sheet O1
Exhibit 7, Tab 1, Schedule 1, Table 3

a) The revenue at current rates reported in Table 3 does not match that in Sheet O1 of the Cost Allocation model. Please reconcile and provide any revised tables/models as necessary.

HHI response: The model filed on conjunction with these responses rectifies this issue.

7.0-VECC – 42

Reference: Cost Allocation Model, Sheet O1
Appendix 2-P

Exhibit 7, Tables 5-7

a) The Revenue to Cost ratios reported in Table 5 of Exhibit 7 do not match those in the Cost Allocation model. Please reconcile.

HHI response: The model filed on conjunction with these responses rectifies this issue.

b) The Base Revenue Requirement by class reported in Table 6 at existing rates does not match that shown in the Cost Allocation model (e.g. for Residential the values are $958,758 versus $883,344). The same observation applies for the Service Revenue Requirement by class at existing rates. Please reconcile.

HHI response: The model filed on conjunction with these responses rectifies this issue.

c) As necessary, please provide corrected versions of the Tables 5 and 6 as well as the Cost Allocation model.

HHI response: The model filed on conjunction with these responses rectifies this issue.

d) The values input into part (B) of Appendix 2-P appear to be incorrect. In particular, as stated in the notes, the totals for columns 7C and 7D should reconcile with the Base Revenue Requirement (whereas those filed match the Service Revenue Requirement). Also, neither the status quo ratios nor the resulting proposed revenue to cost ratios in part (C) match those in the main Application. Please provide a corrected version and ensure that the values reconcile with the Cost Allocation model and Exhibit 7, Tables 5-7 (corrected per part (c) where necessary).

HHI response: The model filed on conjunction with these response rectifies this issue.

7.0-VECC – 43

Reference: Exhibit 7, Tab 1, Schedule 1, Table 7

a) Please confirm that the status quo revenue to cost ratios for GS<50 and GS>50 are both with the Board's policy guidelines.

HHI response: HHI is unclear what VECC is asking. The results from the cost allocation showed that the Street Lights and Sentinel Lights both fell outside of the board range. HHI has moved them within the range as part of this exercise.

b) Please indicate what improvements have been made to the cost allocation and, in particular regarding the customer class load profiles, that would justify moving these ratios closer to 100%, as proposed by HHI.

HHI response: Please note that HHI has filed its application under the 3rd generation IRM and in accordance with the June 28, 2012 filing requirements which state;

"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 (see section 2.6.2 above). In particular, if a rate class has experienced a decline in customers or disappeared, or will disappear in the Test Year, the model must be consistent with the updated load forecast, and include an explanation of the changed load forecast of the rate class."

As can be seen in the Load Forecast, HHI's customer count has not drastically changed since 2010 with the exception of the loss of the large user which was captured in its 2010 Cost Allocation. HHI did not feel that incurring unnecessary costs in updating the customer load profiles was warranted.

EXHIBIT 8 – RATE DESIGN

8.0-Staff-25

Ref: Exhibit 8/ Tab 1/ Page 10-11 – Fixed and Variable Charges;
Exhibit 8/ Tab 9/ Schedule 2

In reference to Exhibit 8/ Tab 1/ Page 11, HHI states:

HHI's current MSC of $5.99 is the lowest in Ontario and has been for many years. The utility's variable charge is the second lowest in Ontario. With Hawkesbury's lack of growth, aging population and high level of unemployment, HHI states that an increase in MSC is necessary to ensure a level of revenue stability for the utility.

a) Based on the most recent 12 months of billing data, please provide the number of Residential customers whose average monthly consumption is within each of the following ranges:

- 0 - 250 kWh
- >250-500 kWh
- >500-800 kWh
- >800-1,000 kWh
- >1,000 kWh

HHI response: Please see table below.

kWh Consumption		
kWh monthly	**# CUSTOMERS WITH AN AVERAGE OF..**	**kWh annualy**
0 - 250 kWh	674	0 - < 3,000
>250-500 kWh	859	> 3,000 - < 6,000
>500-800 kWh	1,216	> 6,000 - < 9,600
>800-1,000 kWh	634	> 9,600 - < 12,000
>1,000 kWh	1,497	> 12,000

b) Please provide Residential bill impact calculations at 250 kWh, 500kWh, 1,000kWh, and 1,500kWh.

HHI Response: The bill impacts are presented at Appendix A of these responses.

c) If any of the total bill impacts provided in (b) is over 10%, please provide an alternative fixed to variable split in order to mitigate the bill impact.

HHI Responses: Although many of the bill impacts are dropping, HHI attests that none of the bill increases exceed 10% and as such, the utility does not need a rate mitigation plan.

8.0-Staff-26

Ref: Exhibit 8/ Tab 1/ Schedule 1 – Fixed and Variable Charges

On Table 1 of the above reference, HHI has used the Bridge year volumes calculating the projected revenue from existing variable charges.

a) Please explain HHI's rationale for using the Bridge year instead of Test year (2014) volumes.

HHI response: HHI should have used the 2014 test year volumes instead of the Bridge Year volumes.

b) Please re-file the table using the Test year volumes.

HHI response: The revised table is presented below

Test Year

	Test Year Projected Revenue from Existing Variable Charges							
Customer Class Name	Variable Distribution Rate	per	Test Year Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Residential	$0.0081	kWh	53,488,924	433,260			0	433,260
General Service < 50 kW	$0.0055	kWh	19,235,278	105,794			0	105,794
General Service > 50 to 4999 kW	$1.5558	kW	201,122	312,906	($0.60)	189,205	-113,523	199,383
Unmetered Scattered Load	$0.0021	kWh	220,649	463			0	463
Sentinel Lighting	$3.2285	kW	292	943	($0.60)			943
Street Lighting	$6.7744	kW	3,211	21,753	($0.60)		0	21,753
Total Variable Revenue			**73,149,476**	**875,119**		**189,205**	**-113,523**	**761,596**

Test Year

	Test Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$5.9900	4,950	355,806	433,260	789,066	45.09%	54.91%	58.58%
General Service < 50 kW	$13.8400	634	105,295	105,794	211,089	49.88%	50.12%	15.67%
General Service > 50 to 4999 kW	$97.3500	98	114,484	199,383	313,866	36.48%	63.52%	23.30%
Unmetered Scattered Load	$6.3900	5	383	463	847	45.28%	54.72%	0.06%
Sentinel Lighting	$1.6300	21	411	943	1,353	30.35%	69.65%	0.10%
Street Lighting	$0.6200	1,215	9,040	21,753	30,792	29.36%	70.64%	2.29%

Total Fixed Revenue			6,923	585,418	761,596	1,347,014			

8.0-Staff-27

Ref: Exhibit 8/ Tab 2/ Schedule 1 – Retail Transmission Service Rates

In the above reference, HHI is proposing adjustments to its RTSRs to offset the over-collection based on its existing rates. It appears that the RTSR model filed by HHI has not been updated based on the latest Uniform Transmission Rates and Hydro One Sub-Transmission Rates.

Please update the RTSR model by using the updated 4.0 version, which is based on the latest Uniform Transmission Rates (EB-2012-0031) and Hydro One Sub-Transmission Rates (EB-2012-0136) and provide the revised RTSR rates.

HHI response: The revised model is filed in conjunction with these responses and the revised rates are also presented in the table below.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential Regular	kWh	$ 0.0070	$ 0.0032
General Service Less Than 50 kW	kWh	$ 0.0064	$ 0.0028
General Service 50 to 4,999 kW	kW	$ 2.5888	$ 1.1437
Unmetered Scattered Load	kWh	$ 0.0064	$ 0.0028
Sentinel Lighting	kW	$ 1.9532	$ 1.8053
Street Lighting	kW	$ 1.9526	$ 0.8842

8.0-Staff-28

Ref: Exhibit 8/ Tab 5/ Schedule 1-2 –Low Voltage Charges

In the above reference, HHI states that the 2013-14 estimates of total LV charges were calculated based on an average of the last 2 years and adjusted upwards to reflect the projected load growth in 2014.

a) Please provide the actual LV charges for the years of 2011 and 2012 and illustrate how the forecast for 2014 LV charge of $97,608 is calculated.

HHI response: The actual charges for 2011 are $96,237.55 net of month end RSVA adjustment and the actual charges for 2012 are $104,326.89.

	2011	2012
LV CHARGES BILLED BY HYDRO ONE	96,237.55	104,326.89
TOTAL YEARLY ADJUSTMENTS TO RSVA NO 1550	(38,101.57)	(47,719.79)
NET EXPENSE RECORDED IN ACCT 4750	**58,135.98**	**56,607.10**

Current rates are understated because they are established using the net expense recorded in acct 4750. They should be established to recover the LV charges billed by Hydro One. The following table shows HHI's Hydro One LV charges.

	2010	2011	2012	2013	2014
LV CHARGES BILLED BY HYDRO ONE (ACCT 4750)	65,152.65	96,237.55	104,326.89	106,000.00	99,595.00

b) In Table 15 of the above reference, the 2013 forecast LV charge is $58,655 and the 2014 forecast LV charge increases to $97,608. Please provide the reason(s) for this increase between the Bridge Year and Test Year.

HHI response: Please see response in section a).

8.0-Staff-29

Ref: Exhibit 8/ Tab 3/ Schedule 1 – Specific Service Charges

HHI is proposing to increase four of its specific service charges which are Change of occupancy charge, Disconnect/Reconnect at meter-after regular hours, Install/Remove load control device-after regular hours, and Service call-after regular hours. In Exhibit 3/ Tab 3/ Schedule 5, HHI states that the current rates are not sufficient to fully recover the actual costs.

Please provide the number of requests HHI has received in previous years (2010, 2011, and 2012) for each of the above service requests.

HHI response: Aside from the change of occupancy charge, HHI does not currently track after hour service calls from regular hour service calls. As mentioned in the application, the reason for the adjustment to the rates is due to the four hour minimum that is paid to the employee as per Union contract. In an effort to respond to the question HHI has provided an estimate based on a ratio of after hour calls. Please find below the information requested.

CHANGE OF OCCUPANCY CHARGE	
	No. Of Requests
YEAR 2010	**993**
YEAR 2011	**939**
YEAR 2012	**976**
Disconnect/Reconnect at meter after regular hours	
	No. Of Requests
YEAR 2010	**6**
YEAR 2011	**4**
YEAR 2012	**2**
Install / remove load control device after regular hours	
	No. Of Requests
YEAR 2010	**0**
YEAR 2011	**0**
YEAR 2012	**0**
Service call after regular hours	
	No. Of Requests
YEAR 2010	**5 to 10 per yr**
YEAR 2011	**5 to 10 per yr**
YEAR 2012	**5 to 10 per yr**

8.0-Staff-30

Ref: Exhibit 8/ Tab 7/ Schedule 1 – Stranded Meters

In Exhibit 8/Tab 7/ Schedule 1, HHI has documented its proposal for recovery of stranded meter rate riders.

a) In Table 9, HHI documents 89.26% allocation of the net book value ("NBV") of stranded meters to the residential class and 10.74% for the GS < 50 kW class. Please provide the basis for the proposed allocation.

HHI response: The utility used the weighted allocation from the smart meter application.

b) Please provide a copy of Sheet I7.1 from HHI's 2010 cost of service rates application.

HHI response: The information requested is presented below.

	Residential			General Service Less than 50kW			General Service 50 to 4,999 kW		
	1	2	3	1	2	3	1	2	3
	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
Allocation Percentage Weighted Factor			64.13%			11%			25%
Cost Relative to Residential Average Cost			1.00			1.45			22.61
Total	4705	235250	50	569.0017637	41152.4515	72.32394366	79.98717949	90438.46154	1130.661965

c) Based on the information provided in b), please provide class-specific SMRRs for the Residential and GS < 50 kW using the capital weighted meter costs and customers to allocate the NBV of stranded meters to the Residential and GS < 50 kW customer classes. Please adequately document the methodology for allocating the costs between the classes. Where available, spreadsheets for documenting the data and calculations should be provided in a working Microsoft Excel format.

HHI response: For the purpose of responding to this IR, HHI updated the information filed in it s2010 Cost Allocation to exclude metering costs from the GS>50 class since they are still on conventional meters. A revised Sheet I7.1 is replicated below.

HHI then updated its stranded meter rate rider to reflect these new weighted average costs. The second table shows the rate rider calculations. The excel format can be found in the revised appendices filed in conjunctions with these responses.

	Residential			General Service Less than 50kW			General Service 50 to 4,999 kW		
	1	2	3	1	2	3	1	2	3
	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
Allocation Percentage Weighted Factor			85.11%			15%			0%
Cost Relative to Residential Average Cost			1.00			1.45			-
Total	4705	235250	50	569.0017637	41152.4515	72.32394366	0	0	-

Stranded Meter Rate Rider

Customer Class Name	Net Book Value	Smart Meters Installed	% share	Annual $	Customer	Rate	per month
Residential	$46,263.24		85.11%	23131.62	4950	$4.67	$0.39
General Service < 50 kW	$8,153.55		15.00%	4076.78	168	$24.27	$2.02
General Service > 50 to 4999 kW							
	TOTAL	**0**					

Total for Recovery				**54,357**
Recovery Period (years)			**2**	
Annual Recovery				**27,179**

d) Please explain why HHI is proposing a two-year recovery period for the proposed stranded meter rate riders.

HHI response: Because HHI cares about its customers and their ability to pay their hydro bills. Although the OEB tends to favor a 1 year disposal period, the utility is of the opinion that its customers should be given as long as possible when it comes to collecting funds from them. The utility also felt that a 2 year disposal period would be in line with the disposition period proposed for its DVA.

8.0-VECC – 44

Reference: Exhibit 8, Tab 1, pages 10 and 15

a) Please explain why HHI believes the fixed-variable splits for USL and Street Lighting should be set "so as to get as close as possible to a 50% fixed 50% variable split" and the split for Sentinel Lights should also get closer to 50%/50%.

HHI Response: If a utility had a choice, they would select a 100% fixed and 0% variable to ensure revenue stability. If a customer had a choice, they would select a 100% variable so that they could have full control over the cost of their hydro bills. A 50/50 split ensures that both the customer and utility's needs are met.

b) The Minimum Fixed Rates and Maximum Fixed Rates reported in Table 5 (page 15) do not match those from the Cost Allocation model (Sheet O2). Please reconcile and provide revised tables as necessary.

HHI Response: As requested by the OEB during the post filing process, the utility was asked to update its cost allocation. The application was not updated to reflect these changes. All models have now been updated to reflect certain changes due to the responses to theses IRs. The rate design tables are presented at Appendix B of this document.

c) Please explain why the fixed portion of the rate design for the GS<50 class is being increased (i.e. $15 versus $14.10 based on current split).

8.0-VECC – 45

Reference: Exhibit 8, Tab 5, Schedule 1

a) Please provide a schedule setting out the calculation of total 2014 LV charges as described in the first paragraph.

HHI Response: HHI has not made any changed to its proposed LV Charges as indicated in the response to 8-Staff 28. The LV calculations are presented below.

Low Voltage Charges

(not loss adjusted)

	2014 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	38.28%	38,122	53,488,924	$0.0007	kWh
General Service < 50 kW	11.93%	11,881	19,235,278	$0.0006	kWh
General Service > 50 to 4999 kW	48.94%	48,741	201,122	$0.2423	kW
Unmetered Scattered Load	0.14%	136	220,649	$0.0006	kWh
Sentinel Lighting	0.11%	112	292	$0.3825	kW
Street Lighting	0.60%	602	3,211	$0.1874	kW
TOTAL	**100.00%**	**99,595**	**73,149,476**		

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**		**2013**			**2014**	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	54,711,762	$0.0004	$21,885	53,488,924	$0.0007	$37,442.25
General Service < 50 kW	kWh	4075	4750	20,128,592	$0.0004	$8,051	19,235,278	$0.0006	$11,541.17
General Service > 50 to 4999 kW	kW	4075	4750	206,144	$0.1369	$28,221	201,122	$0.2423	$48,731.86
Unmetered Scattered Load	kWh	4075	4750	224,238	$0.0004	$90	220,649	$0.0006	$132.39
Sentinel Lighting	kW	4075	4750	297	$0.2162	$64	292	$0.3825	$111.69
Street Lighting	kW	4075	4750	3,250	$0.1059	$344	3,211	$0.1874	$601.74
TOTAL		**0**	**0**	**75,274,283**		**$58,655**	**73,149,476**		**$98,561.10**

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

9.0-Staff-31

Ref: Exhibit 9/ Tab 1/ Schedule 6/ Table 2 - Account 1588 RSVA- Power;
Exhibit 1/ Tab 3/ Schedule 1;
Chapter 2, Cost of Service Filing Requirements for Electricity Distribution Rate Applications dated July 17, 2013, 2.12, p.48-49

HHI provided the 2009 to 2012 Audited Financial Statements as well as Table 2: Energy Sales and Cost of Power Expenses.

Board staff notes that HHI did not provide the reconciliation between the energy sales and cost of power in Table 2 and the 2009-2012 Audited Financial Statements.

Please provide the reconciliation between the total energy sales and cost of power in Table 2 and the total energy sales and cost of power in the 2009 to 2012 Audited Financial Statements and please explain the differences.

HHI response:

Table 2: Energy Sales and Cost of Power Expenses

4006-Residential Energy Sales	-$3,814,622.73	-$3,383,067.89	-$3,107,821.13	-$2,949,767.69
4010-Commercial Energy Sales				
4015-Industrial Energy Sales				
4020-Energy Sales to Large Users				-$408,532.52
4025-Street Lighting Energy Sales	-$29,114.82	-$38,916.09	-$40,735.07	-$71,283.68
4030-Sentinel Lighting Energy Sales	-$6,958.47	-$6,612.10	-$6,692.08	-$6,722.52
4035-General Energy Sales	-$3,004,156.72	-$3,528,577.91	-$3,868,453.29	-$3,715,856.73
4040-Other Energy Sales to Public Authorities				
4050-Revenue Adjustment				
4055-Energy Sales for Resale	-$392,781.55	-$682,613.25	-$868,199.20	-$952,209.82
Total	-$7,247,634.29	-$7,639,787.24	-$7,891,900.77	-$8,104,372.96
4705-Power Purchased	$7,247,634.29	$7,639,787.24	$7,891,900.77	$8,104,372.96

2010 Trial Balance mapped to Audited Financial Statements

Statement of earnings			Trial Balance		
Revenues					
	Energy	**10,221,319**	(3,107,821)	4006-000	RESIDENTIAL Energy Sales
			(3,868,453)	4035-000	GENERAL <50kW Energy Sales
			(40,735)	4025-000	STREETLIGHTS Energy Sales
			(6,692)	4030-000	SENTINEL LIGHTS Energy Sales
			(868,199)	4055-000	RETAILER Energy Sales
			(1,041,786)	4062-000	Billed - WMS
			(792,091)	4066-000	Transmission Network Services
			(461,614)	4068-000	Transmission Connection Serv.
			(33,928)	4075-000	Billed - Low Voltage (LV) Chrg
			(10,221,319)		
	Distribution	**1,210,348**	(1,210,348)	4080-100	Distribution & Service Charge Revenues
			(1,210,348)		

2011 Trial Balance mapped to Audited Financial Statements

Statement of earnings			Trial Balance		
Revenues					
	Energy	**9,895,593**	(3,383,068)	4006-000	RESIDENTIAL Energy Sales
			(3,528,578)	4035-000	GENERAL <50kW Energy Sales
			(38,916)	4025-000	STREETLIGHTS Energy Sales
			(6,612)	4030-000	SENTINEL LIGHTS Energy Sales
			(682,613)	4055-000	RETAILER Energy Sales
			(897,528)	4062-000	Billed - WMS
			(865,148)	4066-000	Transmission Network Services
			(434,995)	4068-000	Transmission Connection Serv.
			(58,136)	4075-000	Billed - Low Voltage (LV) Chrg
			(9,895,594)		
	Distribution	**1,328,430**	(1,328,430)	4080-100	Distribution & Service Charge Revenues
			(1,328,430)		

2012 Trial Balance mapped to Audited Financial Statements

Statement of earnings			Trial Balance		
Revenues					
	Energy	**9,546,720**	(3,814,623)	4006-000	RESIDENTIAL Energy Sales
			(3,004,157)	4035-000	GENERAL <50kW Energy Sales
			(29,115)	4025-000	STREETLIGHTS Energy Sales
			(6,958)	4030-000	SENTINEL LIGHTS Energy Sales
			(392,782)	4055-000	RETAILER Energy Sales
			(880,494)	4062-000	Billed - WMS
			(931,292)	4066-000	Transmission Network Services
			(430,694)	4068-000	Transmission Connection Serv.
			(56,607)	4075-000	Billed - Low Voltage (LV) Chrg
			(9,546,720)		
	Distribution	**1,648,714**	(1,648,714)	4080-100	Distribution & Service Charge Revenues
			(1,648,714)		

Hawkesbury Hydro Inc.
Statement of earnings
year ended December 31, 2010

Hydro Hawkesbury Inc.
État des résultats
de l'exercice terminé le 31 décembre 2010

	2010	2009	
	$	$	
Revenues (Note 11)			**Revenus (note 11)**
Energy	10,221,319	10,647,223	Énergie
Distribution	1,210,348	1,090,418	Distribution
	11,431,667	11,737,641	
Cost of power	10,221,319	10,647,223	Coût de l'énergie
	1,210,348	1,090,418	
Other operating revenues	199,285	219,165	Autres revenus d'exploitation
	1,409,633	1,309,583	

Hawkesbury Hydro Inc.
Statement of earnings
year ended December 31, 2011

Hydro Hawkesbury Inc.
État des résultats
de l'exercice clos le 31 décembre 2011

	2011	2010	
	$	$	
Revenues			**Revenus**
Energy (Note 12)	9,895,593	10,221,319	Énergie (note 12)
Distribution (Note 12)	1,328,430	1,210,348	Distribution (note 12)
Other operating revenues	173,830	199,285	Autres revenus d'exploitation
	11,397,853	11,630,952	
Cost of power	9,895,593	10,221,319	Coût de l'énergie
	1,502,260	1,409,633	

Hawkesbury Hydro Inc.
Statement of earnings
year ended December 31, 2012

Hydro Hawkesbury Inc.
État des résultats
de l'exercice clos le 31 décembre 2012

	2012	2011	
	$	$	
Revenues			**Revenus**
Energy (Note 11)	9,546,720	9,895,593	Énergie (note 11)
Distribution (Note 11)	1,648,714	1,328,430	Distribution (note 11)
Other operating revenues	183,270	173,830	Autres revenus d'exploitation
	11,378,704	11,397,853	
Cost of power	9,546,720	9,895,593	Coût de l'énergie
	1,831,984	1,502,260	

9.0-Staff-32

Ref: Exhibit 9/ Tab 1/ Schedule 9/ Page 22-23 - LRAMVA

HHI notes that it has sought disposition of the total LRAMVA balance of $6,818 which includes $1,423 in residual balances from the previous LRAM Rate Rider. HHI goes on to state that it is requesting disposition of the December 31, 2012 audited balance, plus forecasted interest through December 30, 2013 of a debit balance of $5,316.60 as detailed in Section E4.T7.S2 with carrying charges calculated at $78.

Also, Board staff notes that it has been the Board's practice not to true-up approved LRAM amounts.

a) Please reconcile the statements in the first paragraph and confirm the total LRAMVA balance for which HHI is seeking approval.

b) Please discuss the residual LRAM rate rider balance of $1,423 and explain why HHI believes it is appropriate to true-up a historically approved LRAM amount.

HHI response a) b): HHI is of the opinion that variance accounts are created to capture the difference between the amount charged and the amount collected. It is not clear to HHI why residual amounts under-collected from historical approved LRAM amount should be written off by the utility.

c) Please provide an updated LRAMVA amount excluding the residual LRAM balances.
d) Please provide an updated rate rider table reflecting the confirmed LRAMVA balance for which HHI is seeking approval.

HHI response a) c) d): HHI seeks to recover its allowable and eligible LRAM savings in accordance with the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13.5 and Appendix A. Unfortunately, it is no longer clear to utilities which methodology they should use to calculated these savings especially given the OPA's new reporting format which exclude persistence's and net to gross adjustments which seem to be factored in to the OEB appendices. The table below shows the recovery of LRAMVA as it understands it. If HHI has misunderstood the methodology, it will gladly work with Board Staff to rectify this table.

LRAMVA Calculations

	2011 (1)	2012 (2)	2013	
LRAM Claim (kW):	149	150		(1) tab 3.1.1 of Final 2011 OPA report
LRAM Claim (kWh):	717,718	685,247		(2) Annual report 2012 (word document)

Per class allocation (kWh)	2011 Alloc by Class	2012 Alloc by Class	2011 LRAM (kWh)	2012 LRAM (kWh)	Total
Residential	**33.27%**	**34.27%**	238,754.39	234,823.92	473,578.31
General Service < 50 kW	**11.98%**	**12.42%**	85,947.21	85,103.93	171,051.14
General Service > 50 to 4999 kW	**53.68%**	**52.19%**	385,277.94	357,635.51	742,913.45
Unmetered Scattered Load	**0.14%**	**0.14%**	1,002.54	986.92	1,989.46
Sentinel Lighting	**0.07%**	**0.07%**	479.11	470.05	949.16
Street Lighting	**0.87%**	**0.91%**	6,256.82	6,226.67	12,483.49
	100%	**100%**	**717,718**	**685,247**	**1,402,965**

Per class allocation (kW)	2011 Alloc by Class	2012 Alloc by Class	kW	kW	Total
General Service > 50 to 4999 kW	**98.14%**	**98.09%**	146.23	147.13	293.36
Sentinel Lighting	**0.13%**	**0.13%**	0.19	0.20	0.40
Street Lighting	**1.73%**	**1.78%**	2.57	2.67	5.24
			2.57	**150.00**	**299.00**

LRAMVA Rate Rider	2011 Volumetric Rate	2012 Volumetric Rate	2011 LRAM	2012 LRAM	Entry to 1568
Residential	0.0079	0.0080	$1,886.16	$1,878.59	$3,764.75
General Service < 50 kW	0.0054	0.0055	$464.11	$468.07	$932.19
General Service > 50 to 4999 kW	1.5288	1.5453	$223.56	$227.36	$450.92
Unmetered Scattered Load	0.0021	0.0021	$2.11	$2.07	$4.18
Sentinel Lighting	3.1724	3.2067	$0.61	$0.65	$1.26
Street Lighting	6.6567	6.7286	$17.13	$17.95	$35.08
			$2,593.68	**$2,594.70**	**$5,188.38**

carrying charges		**$76.27**
Total		**$5,264.65**

9.0-Staff-33

Ref: HHI's responses to the Board letter requesting additional information dated September 11, 2013 – Account 1576, Accounting Changes under CGAAP; Board letter dated June 25, 2013 regarding Policy Changes for Account 1575 & 1576; Exhibit 2/ Tab 2/ Schedule 6

In Exhibit 2/ Tab 2/ Schedule 6, HHI indicates that indirect overhead costs, such as general and administrative costs that are not directly attributable to an asset, are no longer capitalized as of January 1, 2013.

In the light of HHI's new capitalization policy on indirect overhead, Board staff notes that in Appendices 2-B for 2013, there were no changes in the total cost additions for the fixed assets accounts and notes that the total cost additions of $2,603,100 in Appendix 2-EE are the same under both the Old CGAAP and New CGAAP.

a) Please explain why the total additions for 2013 in Appendices 2-B under the New CGAAP have not changed in accordance with HHI's new capitalization policy, and please update all related evidence to reflect the change in new capitalization policy effective on January 1, 2013.

HHI response: Old CGAAP additions should have been $6,000 higher than New CGAAP- this to reflect the burdens.

In the June 25, 2013 Board letter to Licensed Electricity Distributors and All other Interested Parties, the Board states:

> The Board will require the use of separate rate riders for the disposition of the balances in Accounts 1575 and 1576.

Board staff also notes that HHI did not provide a separate calculation for the rate rider for Account 1576 for the credit balance of $30,580.

b) HHI incorrectly included the balance in Account 1575 for disposition in Attachment 2 of the September 11, 2013 response. Please make the correction in the evidence to show the disposition of the balance recorded in Account 1576 rather than Account 1575. If HHI is of the view that this change should not be made, please explain why.
c) Please remove the credit balance of $30,580 in Account 1575 shown in Attachment 2 from the total account balances ($181,860) and file the recalculated new total account balances allocated to each rate class (1588 excluding sub account GA). In addition, please re-file the rate riders for the Deferral/Variance Accounts (Account 1588 Excluding GA). If HHI is of the view that this change should not be made, please explain why.
d) Please calculate and file separate rate riders for each class for the disposition of the balance of Account 1576.

HHI response for all of the above: Please note that when the application was filed in May of 2013, the appendices which calculated the balance of 1576 had not been released yet. The revised appendices and the EDVVAR model filed on conjunction with these responses rectify these issues.

~All of the above are respectfully submitted~

Appendix A – Bill Impacts

File Number:	EB-2013-0139
Exhibit:	8
Tab:	8
Schedule:	2
Page:	
Date:	

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 250 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 5.99	1	$ 5.99	$ 10.00	1	$ 10.00	$ 4.01	66.94%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.39	1	$ 0.39	$ 0.39	
SMIRR	Monthly	$ 1.39	1	$ 1.39		1	$ -	-$ 1.39	-100.00%
SMDR	Monthly	-$ 1.35	1	-$ 1.35		1	$ -	$ 1.35	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0081	250	$ 2.03	$ 0.0064	250	$ 1.59	-$ 0.43	-21.47%
Smart Meter Disposition Rider	per kWh		250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		250	$ -		250	$ -	$ -	
	per kWh		250	$ -		250	$ -	$ -	
Incremental Capital Rate Rider	per kWh	$ 0.0024	250	$ 0.60		250	$ -	-$ 0.60	-100.00%
Account 1576	per kWh		250	$ -	$ 0.0033	250	$ 0.83	$ 0.83	
	Monthly		250	$ -		1	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Low Voltage	per kWh		250	$ -	$ 0.0007	250	$ 0.18	$ 0.18	
Sub-Total A				$ 8.66			$ 12.98	**$ 4.33**	**50.02%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	250	$ 0.28	-$ 0.0018	250	-$ 0.46	-$ 0.73	-266.12%
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	250	$ 0.10		250	$ -	-$ 0.10	-100.00%
Smart Meter Entity Charge	Monthly	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 9.03**			**$ 12.53**	**$ 3.50**	**38.73%**
RTSR - Network	per kWh	$ 0.0069	261	$ 1.80	$ 0.0070	264	$ 1.84	$ 0.04	2.31%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	261	$ 0.81	$ 0.0032	264	$ 0.83	$ 0.02	3.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.64**			**$ 15.21**	**$ 3.56**	**30.61%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	261	$ 1.15	$ 0.0044	264	$ 1.16	$ 0.01	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	261	$ 0.31	$ 0.0012	264	$ 0.32	$ 0.00	0.90%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	261	$ 0.18	$ 0.0007	264	$ 0.18	$ 0.00	0.90%
Energy - RPP - Tier 1	per kWh	$ 0.0750	261	$ 19.59	$ 0.0750	264	$ 19.76	$ 0.18	0.90%
Energy - RPP - Tier 2	per kWh	$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0650	167	$ 10.86	$ 0.0650	169	$ 10.96	$ 0.10	0.90%
TOU - Mid Peak	per kWh	$ 0.1000	47	$ 4.70	$ 0.1000	47	$ 4.74	$ 0.04	0.90%
TOU - On Peak	per kWh	$ 0.1170	47	$ 5.50	$ 0.1170	47	$ 5.55	$ 0.05	0.90%
Total Bill on RPP (before Taxes)				**$ 33.12**			**$ 36.88**	**$ 3.76**	**11.34%**
HST		13%		$ 4.31	13%		$ 4.79	$ 0.49	11.34%
Total Bill (including HST)				$ 37.43			$ 41.67	$ 4.24	11.34%
Ontario Clean Energy Benefit [1]				-$ 3.74			-$ 4.17	-$ 0.43	11.50%
Total Bill on RPP (including OCEB)				**$ 33.69**			**$ 37.50**	**$ 3.81**	**11.32%**
Total Bill on TOU (before Taxes)				**$ 34.60**			**$ 38.37**	**$ 3.77**	**10.89%**
HST		13%		$ 4.50	13%		$ 4.99	$ 0.49	10.89%
Total Bill (including HST)				$ 39.10			$ 43.36	$ 4.26	10.89%
Ontario Clean Energy Benefit [1]				-$ 3.91			-$ 4.34	-$ 0.43	11.00%
Total Bill on TOU (including OCEB)				**$ 35.19**			**$ 39.02**	**$ 3.83**	**10.88%**

Loss Factor (%) 4.47% 5.41%

[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.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 500 **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	Monthly	$ 5.99	1	$ 5.99	$ 10.00	1	$ 10.00	$ 4.01	66.94%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.39	1	$ 0.39	$ 0.39	
SMIRR	Monthly	$ 1.39	1	$ 1.39		1	$ -	-$ 1.39	-100.00%
SMDR	Monthly	-$ 1.35	1	-$ 1.35		1	$ -	$ 1.35	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0081	500	$ 4.05	$ 0.0064	500	$ 3.18	-$ 0.87	-21.47%
Smart Meter Disposition Rider	per kWh		500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		500	$ -		500	$ -	$ -	
	per kWh		500	$ -		500	$ -	$ -	
Incremental Capital Rate Rider	per kWh	$ 0.0024	500	$ 1.20		500	$ -	-$ 1.20	-100.00%
Account 1576	per kWh		500	$ -	$ 0.0033	500	$ 1.66	$ 1.66	
	Monthly		500	$ -		1	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage	per kWh		500	$ -	$ 0.0007	500	$ 0.35	$ 0.35	
Sub-Total A				$ 11.28			$ 15.58	**$ 4.30**	**38.11%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	500	$ 0.55	-$ 0.0018	500	-$ 0.91	-$ 1.46	-266.12%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	500	$ 0.20		500	$ -	-$ 0.20	-100.00%
Smart Meter Entity Charge	Monthly	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 12.03**			**$ 14.66**	**$ 2.63**	**21.90%**
RTSR - Network	per kWh	$ 0.0069	522	$ 3.60	$ 0.0070	527	$ 3.69	$ 0.08	2.31%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	522	$ 1.62	$ 0.0032	527	$ 1.67	$ 0.05	3.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 17.25**			**$ 20.02**	**$ 2.77**	**16.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	522	$ 2.30	$ 0.0044	527	$ 2.32	$ 0.02	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	522	$ 0.63	$ 0.0012	527	$ 0.63	$ 0.01	0.90%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	522	$ 0.37	$ 0.0007	527	$ 0.37	$ 0.00	0.90%
Energy - RPP - Tier 1	per kWh	$ 0.0750	522	$ 39.17	$ 0.0750	527	$ 39.53	$ 0.35	0.90%
Energy - RPP - Tier 2	per kWh	$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0650	334	$ 21.73	$ 0.0650	337	$ 21.93	$ 0.20	0.90%
TOU - Mid Peak	per kWh	$ 0.1000	94	$ 9.40	$ 0.1000	95	$ 9.49	$ 0.09	0.90%
TOU - On Peak	per kWh	$ 0.1170	94	$ 11.00	$ 0.1170	95	$ 11.10	$ 0.10	0.90%
Total Bill on RPP (before Taxes)				**$ 59.97**			**$ 63.12**	**$ 3.15**	**5.26%**
HST		13%		$ 7.80	13%		$ 8.21	$ 0.41	5.26%
Total Bill (including HST)				$ 67.76			$ 71.33	$ 3.56	5.26%
Ontario Clean Energy Benefit [1]				-$ 6.78			-$ 7.13	-$ 0.35	5.16%
Total Bill on RPP (including OCEB)				**$ 60.98**			**$ 64.20**	**$ 3.21**	**5.27%**
Total Bill on TOU (before Taxes)				**$ 62.92**			**$ 66.10**	**$ 3.18**	**5.05%**
HST		13%		$ 8.18	13%		$ 8.59	$ 0.41	5.05%
Total Bill (including HST)				$ 71.10			$ 74.70	$ 3.59	5.05%
Ontario Clean Energy Benefit [1]				-$ 7.11			-$ 7.47	-$ 0.36	5.06%
Total Bill on TOU (including OCEB)				**$ 63.99**			**$ 67.23**	**$ 3.23**	**5.05%**

Loss Factor (%) — Current: 4.47% — Proposed: 5.41%

[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.

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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 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	Monthly	$ 5.99	1	$ 5.99	$ 10.00	1	$ 10.00	$ 4.01	66.94%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.39	1	$ 0.39	$ 0.39	
SMIRR	Monthly	$ 1.39	1	$ 1.39		1	$ -	-$ 1.39	-100.00%
SMDR	Monthly	-$ 1.35	1	-$ 1.35		1	$ -	$ 1.35	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0081	800	$ 6.48	$ 0.0064	800	$ 5.09	-$ 1.39	-21.47%
Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		800	$ -		800	$ -	$ -	
	per kWh		800	$ -		800	$ -	$ -	
Incremental Capital Rate Rider	per kWh	$ 0.0024	800	$ 1.92		800	$ -	-$ 1.92	-100.00%
Account 1576	per kWh		800	$ -	$ 0.0033	800	$ 2.65	$ 2.65	
	Monthly		800	$ -		1	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage	per kWh		800	$ -	$ 0.0007	800	$ 0.56	$ 0.56	
Sub-Total A				$ 14.43			$ 18.69	**$ 4.26**	**29.54%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	800	$ 0.88	-$ 0.0018	800	-$ 1.46	-$ 2.34	-266.12%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
Smart Meter Entity Charge	Monthly	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 15.63**			**$ 17.23**	**$ 1.60**	**10.24%**
RTSR - Network	per kWh	$ 0.0069	836	$ 5.77	$ 0.0070	843	$ 5.90	$ 0.13	2.31%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	836	$ 2.59	$ 0.0032	843	$ 2.67	$ 0.08	3.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 23.99**			**$ 25.80**	**$ 1.81**	**7.56%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	836	$ 3.68	$ 0.0044	843	$ 3.71	$ 0.03	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	836	$ 1.00	$ 0.0012	843	$ 1.01	$ 0.01	0.90%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	836	$ 0.59	$ 0.0007	843	$ 0.59	$ 0.01	0.90%
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	236	$ 20.74	$ 0.0880	243	$ 21.41	$ 0.67	3.21%
TOU - Off Peak	per kWh	$ 0.0650	535	$ 34.77	$ 0.0650	540	$ 35.08	$ 0.31	0.90%
TOU - Mid Peak	per kWh	$ 0.1000	150	$ 15.04	$ 0.1000	152	$ 15.18	$ 0.14	0.90%
TOU - On Peak	per kWh	$ 0.1170	150	$ 17.60	$ 0.1170	152	$ 17.76	$ 0.16	0.90%
Total Bill on RPP (before Taxes)				**$ 95.25**			**$ 97.77**	**$ 2.53**	**2.65%**
HST		13%		$ 12.38	13%		$ 12.71	$ 0.33	2.65%
Total Bill (including HST)				$ 107.63			$ 110.48	$ 2.85	2.65%
Ontario Clean Energy Benefit [1]				-$ 10.76			-$ 11.05	-$ 0.29	2.70%
Total Bill on RPP (including OCEB)				**$ 96.87**			**$ 99.43**	**$ 2.56**	**2.65%**
Total Bill on TOU (before Taxes)				**$ 96.91**			**$ 99.38**	**$ 2.47**	**2.55%**
HST		13%		$ 12.60	13%		$ 12.92	$ 0.32	2.55%
Total Bill (including HST)				$ 109.51			$ 112.30	$ 2.79	2.55%
Ontario Clean Energy Benefit [1]				-$ 10.95			-$ 11.23	-$ 0.28	2.56%
Total Bill on TOU (including OCEB)				**$ 98.56**			**$ 101.07**	**$ 2.51**	**2.55%**

Loss Factor (%) — Current: 4.47% — Proposed: 5.41%

[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.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service < 50 kW**

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 13.84	1	$ 13.84	$ 15.00	1	$ 15.00	$ 1.16	8.38%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 2.02	1	$ 2.02	$ 2.02	
SMIRR	Monthly	$ 2.46	1	$ 2.46		1	$ -	-$ 2.46	-100.00%
SMDR	Monthly	-$ 0.09	1	-$ 0.09		1	$ -	$ 0.09	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0055	2000	$ 11.00	$ 0.0063	2000	$ 12.61	$ 1.61	14.62%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 0.0017	2000	$ 3.40		2000	$ -	-$ 3.40	-100.00%
Account 1576			2000	$ -	$ 0.0033	2000	$ 6.63	$ 6.63	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 30.61			$ 36.26	**$ 5.65**	**18.47%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	2000	$ 2.20	-$ 0.0015	2000	-$ 2.91	-$ 5.11	-232.08%
Global Adj DVA	per kWh	$ 0.0060	2000	$ 12.00	$ 0.0033	2000	$ 6.63	-$ 5.37	-44.71%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	2000	$ 0.80	$ 0.0006	2000	$ 1.20	$ 0.40	50.00%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.79	2000	$ 1,580.00	$ 1,579.21	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 45.61**			**$ 41.19**	**-$ 4.42**	**-9.68%**
RTSR - Network	per kWh	$ 0.0063	2089	$ 13.16	$ 0.0064	2108	$ 13.47	$ 0.30	2.31%
RTSR - Line and Transformation Connection	per kWh	$ 0.0027	2089	$ 5.64	$ 0.0028	2108	$ 5.81	$ 0.17	3.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 64.41**			**$ 60.47**	**-$ 3.94**	**-6.12%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2089	$ 9.19	$ 0.0044	2108	$ 9.28	$ 0.08	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2089	$ 2.51	$ 0.0012	2108	$ 2.53	$ 0.02	0.90%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0007	2089	$ 1.46	$ 0.0007	2108	$ 1.48	$ 0.01	0.90%
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	1489	$ 131.06	$ 0.0880	1508	$ 132.72	$ 1.66	1.27%
TOU - Off Peak	per kWh	$ 0.0650	1337	$ 86.91	$ 0.0650	1349	$ 87.70	$ 0.79	0.90%
TOU - Mid Peak	per kWh	$ 0.1000	376	$ 37.61	$ 0.1000	379	$ 37.95	$ 0.34	0.90%
TOU - On Peak	per kWh	$ 0.1170	376	$ 44.00	$ 0.1170	379	$ 44.40	$ 0.40	0.90%
Total Bill on RPP (before Taxes)				**$ 253.88**			**$ 251.73**	**-$ 2.16**	**-0.85%**
HST		13%		$ 33.01	13%		$ 32.72	-$ 0.28	-0.85%
Total Bill (including HST)				$ 286.89			$ 284.45	-$ 2.44	-0.85%
Ontario Clean Energy Benefit [1]				-$ 28.69			-$ 28.45	$ 0.24	-0.84%
Total Bill on RPP (including OCEB)				**$ 258.20**			**$ 256.00**	**-$ 2.20**	**-0.85%**
Total Bill on TOU (before Taxes)				**$ 246.35**			**$ 244.05**	**-$ 2.30**	**-0.93%**
HST		13%		$ 32.03	13%		$ 31.73	-$ 0.30	-0.93%
Total Bill (including HST)				$ 278.37			$ 275.78	-$ 2.59	-0.93%
Ontario Clean Energy Benefit [1]				-$ 27.84			-$ 27.58	$ 0.26	-0.93%
Total Bill on TOU (including OCEB)				**$ 250.53**			**$ 248.20**	**-$ 2.33**	**-0.93%**

	Current	Proposed
Loss Factor (%)	4.47%	5.41%

[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.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service > 50 to 4999 kW**

Consumption 240 **kW** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after O

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 97.3500	1	$ 97.35	$ 97.3500	1	$ 97.35	$ -	0.00%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.5558	240	$ 373.39	$ 2.1601	240	$ 518.43	$ 145.03	38.84%
Smart Meter Disposition Rider			240	$ -		240	$ -	$ -	
LRAM & SSM Rate Rider			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 1.3270	240	$ 318.48		240	$ -	-$ 318.48	-100.00%
Account 1576			240	$ -	$ 1.2501	240	$ 300.03	$ 300.03	
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
Sub-Total A				$ 789.22			$ 915.81	**$ 126.59**	**16.04%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.4219	240	$ 101.26	-$ 0.1753	240	-$ 42.07	-$ 143.33	-141.55%
Global Adj DVA	per kW	$ 2.3612	240	$ 566.69	$ 1.2501	240	$ 300.03	-$ 266.65	-47.05%
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1369	240	$ 32.86	$ 0.2431	240	$ 58.34	$ 25.49	77.57%
Smart Meter Entity Charge						240	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,490.02**			**$ 1,232.12**	**-$ 257.90**	**-17.31%**
RTSR - Network		$ 2.5533	251	$ 640.15	$ 2.5888	253	$ 654.93	$ 14.78	2.31%
RTSR - Line and Transformation Connection		$ 1.1197	251	$ 280.73	$ 1.1437	253	$ 289.34	$ 8.61	3.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,410.90**			**$ 2,176.39**	**-$ 234.51**	**-9.73%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	251	$ 1.10	$ 0.0044	253	$ 1.11	$ 0.01	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	251	$ 0.30	$ 0.0012	253	$ 0.30	$ 0.00	0.90%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		per kWh		$ 0.0007	0 $ -		$ 0.0007	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	251	$ 18.80	$ 0.0750	253	$ 18.97	$ 0.17	0.90%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	160	$ 10.43	$ 0.0650	162	$ 10.52	$ 0.09	0.90%
TOU - Mid Peak		$ 0.1000	45	$ 4.51	$ 0.1000	46	$ 4.55	$ 0.04	0.90%
TOU - On Peak		$ 0.1170	45	$ 5.28	$ 0.1170	46	$ 5.33	$ 0.05	0.90%
Total Bill on RPP (before Taxes)				**$ 2,431.36**			**$ 2,197.03**	**-$ 234.33**	**-9.64%**
HST		13%		$ 316.08	13%		$ 285.61	-$ 30.46	-9.64%
Total Bill (including HST)				$ 2,747.44			$ 2,482.64	-$ 264.79	-9.64%
Ontario Clean Energy Benefit [1]				-$ 274.74			-$ 248.26	$ 26.48	-9.64%
Total Bill on RPP (including OCEB)				**$ 2,472.70**			**$ 2,234.38**	**-$ 238.31**	**-9.64%**
Total Bill on TOU (before Taxes)				**$ 2,432.78**			**$ 2,198.46**	**-$ 234.32**	**-9.63%**
HST		13%		$ 316.26	13%		$ 285.80	-$ 30.46	-9.63%
Total Bill (including HST)				$ 2,749.04			$ 2,484.26	-$ 264.78	-9.63%
Ontario Clean Energy Benefit [1]				-$ 274.90			-$ 248.43	$ 26.47	-9.63%
Total Bill on TOU (including OCEB)				**$ 2,474.14**			**$ 2,235.83**	**-$ 238.31**	**-9.63%**
Loss Factor (%)		4.47%			5.41%				

[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.

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Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 4600 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 6.39	1	$ 6.39	$ 8.50	1	$ 8.50	$ 2.11	33.02%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0021	4600	$ 9.66	$ 0.0021	4600	$ 9.70	$ 0.04	0.38%
Smart Meter Disposition Rider			4600	$ -		4600	$ -	$ -	
LRAM & SSM Rate Rider			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
Incremental Capital Rate Rider	per kWh	$ 0.0006	4600	$ 2.76		4600	$ -	-$ 2.76	-100.00%
Account 1576			4600	$ -	$ 0.0033	4600	$ 15.26	$ 15.26	
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
Sub-Total A				$ 18.81			$ 33.46	**$ 14.65**	**77.86%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	4600	$ 5.06	$ 0.0002	4600	$ 0.92	-$ 4.14	-81.82%
Global Adj DVA	per kWh	$ 0.0060	4600	$ 27.60	$ 0.0033	4600	$ 15.26	-$ 12.34	-44.71%
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	4600	$ 1.84	$ 0.0006	4600	$ 2.76	$ 0.92	50.00%
Smart Meter Entity Charge						4600	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 53.31**			**$ 52.40**	**-$ 0.91**	**-1.72%**
RTSR - Network	per kWh	$ 0.0063	4805	$ 30.27	$ 0.0064	4849	$ 30.97	$ 0.70	2.31%
RTSR - Line and Transformation Connection	per kWh	$ 0.0027	4805	$ 12.97	$ 0.0028	4849	$ 13.37	$ 0.40	3.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 96.56**			**$ 96.74**	**$ 0.18**	**0.19%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	4805	$ 21.14	$ 0.0044	4849	$ 21.33	$ 0.19	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	4805	$ 5.77	$ 0.0012	4849	$ 5.82	$ 0.05	0.90%
Standard Supply Service Charge	per kWh	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		per kWh		$ 0.0007 0	$ -		$ 0.0007	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	4205	$ 370.07	$ 0.0880	4249	$ 373.90	$ 3.83	1.03%
TOU - Off Peak		$ 0.0650	3075	$ 199.90	$ 0.0650	3103	$ 201.71	$ 1.81	0.90%
TOU - Mid Peak		$ 0.1000	865	$ 86.50	$ 0.1000	873	$ 87.28	$ 0.78	0.90%
TOU - On Peak		$ 0.1170	865	$ 101.20	$ 0.1170	873	$ 102.12	$ 0.92	0.90%
Total Bill on RPP (before Taxes)				**$ 538.79**			**$ 543.05**	**$ 4.25**	**0.79%**
HST		13%		$ 70.04	13%		$ 70.60	$ 0.55	0.79%
Total Bill (including HST)				$ 608.84			$ 613.64	$ 4.80	0.79%
Ontario Clean Energy Benefit [1]				-$ 60.88			-$ 61.36	-$ 0.48	0.79%
Total Bill on RPP (including OCEB)				**$ 547.96**			**$ 552.28**	**$ 4.32**	**0.79%**
Total Bill on TOU (before Taxes)				**$ 511.32**			**$ 515.25**	**$ 3.93**	**0.77%**
HST		13%		$ 66.47	13%		$ 66.98	$ 0.51	0.77%
Total Bill (including HST)				$ 577.79			$ 582.24	$ 4.44	0.77%
Ontario Clean Energy Benefit [1]				-$ 57.78			-$ 58.22	-$ 0.44	0.76%
Total Bill on TOU (including OCEB)				**$ 520.01**			**$ 524.02**	**$ 4.00**	**0.77%**

Loss Factor (%)	4.47%	5.41%

[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.

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Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

Consumption 1.3 **kW** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 1.63	1	$ 1.63	$ 1.0000	1	$ 1.00	-$ 0.63	-38.65%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.2285	1.3	$ 4.20	$ 1.8742	1.3	$ 2.44	-$ 1.76	-41.95%
Smart Meter Disposition Rider			1.3	$ -		1.3	$ -	$ -	
LRAM & SSM Rate Rider			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 0.7496	1.3	$ 0.97		1.3	$ -	-$ 0.97	-100.00%
Account 1576			1.3	$ -	$ 1.1955	1.3	$ 1.55	$ 1.55	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
Sub-Total A				$ 6.80			$ 4.99	**-$ 1.81**	**-26.62%**
Deferral/Variance Account Disposition Rate Rider	per kW		1.3	$ -	-$ 0.4301	1.3	-$ 0.56	-$ 0.56	
Global Adj DVA	per kW		1.3	$ -	$ 1.1991	1.3	$ 1.56	$ 1.56	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.2162	1.3	$ 0.28	$ 0.1880	1.3	$ 0.24	-$ 0.04	-13.04%
Smart Meter Entity Charge						1.3	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.08**			**$ 6.23**	**-$ 0.85**	**-11.97%**
RTSR - Network	per kW	$ 1.9264	1	$ 2.62	$ 1.9526	1	$ 2.68	$ 0.06	2.28%
RTSR - Line and Transformation Connection	per kW	$ 1.7674	1	$ 2.40	$ 0.8842	1	$ 1.21	-$ 1.19	-49.52%
Sub-Total C - Delivery (including Sub-Total B)				**$ 12.10**			**$ 10.12**	**-$ 1.98**	**-16.34%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1	$ 0.01	$ 0.0044	1	$ 0.01	$ 0.00	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1	$ 0.00	$ 0.0012	1	$ 0.00	$ 0.00	0.90%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		per kWh		$ 0.0007 0	$ -		$ 0.0007	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	1	$ 0.10	$ 0.0750	1	$ 0.10	$ 0.00	0.90%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	1	$ 0.06	$ 0.0650	1	$ 0.06	$ 0.00	0.90%
TOU - Mid Peak		$ 0.1000	0	$ 0.02	$ 0.1000	0	$ 0.02	$ 0.00	0.90%
TOU - On Peak		$ 0.1170	0	$ 0.03	$ 0.1170	0	$ 0.03	$ 0.00	0.90%
Total Bill on RPP (before Taxes)				**$ 12.46**			**$ 10.48**	**-$ 1.98**	**-15.86%**
HST		13%		$ 1.62	13%		$ 1.36	-$ 0.26	-15.86%
Total Bill (including HST)				$ 14.08			$ 11.85	-$ 2.23	-15.86%
Ontario Clean Energy Benefit [1]				-$ 1.41			-$ 1.18	$ 0.23	-16.31%
Total Bill on RPP (including OCEB)				**$ 12.67**			**$ 10.67**	**-$ 2.00**	**-15.81%**
Total Bill on TOU (before Taxes)				**$ 12.47**			**$ 10.49**	**-$ 1.98**	**-15.85%**
HST		13%		$ 1.62	13%		$ 1.36	-$ 0.26	-15.85%
Total Bill (including HST)				$ 14.09			$ 11.85	-$ 2.23	-15.85%
Ontario Clean Energy Benefit [1]				-$ 1.41			-$ 1.19	$ 0.22	-15.60%
Total Bill on TOU (including OCEB)				**$ 12.68**			**$ 10.66**	**-$ 2.01**	**-15.88%**
Loss Factor (%)		4.47%			5.41%				

[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.

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Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 0.23 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 0.6200	1	$ 0.62	$ 1.0000	1	$ 1.00	$ 0.38	61.29%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.7744	0.23	$ 1.56	$ 1.8742	0.23	$ 0.43	-$ 1.13	-72.33%
Smart Meter Disposition Rider			0.23	$ -		0.23	$ -	$ -	
LRAM & SSM Rate Rider			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 1.5987	0.23	$ 0.37		0.23	$ -	-$ 0.37	-100.00%
Account 1576			0.23	$ -	$ 1.1991	0.23	$ 0.28	$ 0.28	
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
Sub-Total A				$ 2.55			$ 1.71	**-$ 0.84**	**-32.95%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.3898	0.23	$ 0.09	-$ 0.4301	0.23	-$ 0.10	-$ 0.19	-210.34%
Global Adj DVA	per kW	$ 2.1767	0.23	$ 0.50	$ 1.1991	0.23	$ 0.28	-$ 0.22	-44.91%
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1059	0.23	$ 0.02	$ 0.1880	0.23	$ 0.04	$ 0.02	77.53%
Smart Meter Entity Charge						0.23	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3.16**			**$ 1.93**	**-$ 1.23**	**-39.03%**
RTSR - Network	per kW	$ 1.9258	0	$ 0.46	$ 1.9526	0	$ 0.47	$ 0.01	2.31%
RTSR - Line and Transformation Connection	per kW	$ 0.8656	0	$ 0.21	$ 0.8842	0	$ 0.21	$ 0.01	3.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3.83**			**$ 2.61**	**-$ 1.22**	**-31.75%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	0	$ 0.00	$ 0.0044	0	$ 0.00	$ 0.00	0.90%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	0	$ 0.00	$ 0.0012	0	$ 0.00	$ 0.00	0.90%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		per kWh		$ 0.0007	0 $ -		$ 0.0007	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	0	$ 0.02	$ 0.0750	0	$ 0.02	$ 0.00	0.90%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	0	$ 0.01	$ 0.0650	0	$ 0.01	$ 0.00	0.90%
TOU - Mid Peak		$ 0.1000	0	$ 0.00	$ 0.1000	0	$ 0.00	$ 0.00	0.90%
TOU - On Peak		$ 0.1170	0	$ 0.01	$ 0.1170	0	$ 0.01	$ 0.00	0.90%
Total Bill on RPP (before Taxes)				**$ 4.10**			**$ 2.88**	**-$ 1.22**	**-29.66%**
HST		13%		$ 0.53	13%		$ 0.38	-$ 0.16	-29.66%
Total Bill (including HST)				$ 4.63			$ 3.26	-$ 1.37	-29.66%
Ontario Clean Energy Benefit [1]				-$ 0.46			-$ 0.33	$ 0.13	-28.26%
Total Bill on RPP (including OCEB)				**$ 4.17**			**$ 2.93**	**-$ 1.24**	**-29.81%**
Total Bill on TOU (before Taxes)				**$ 4.10**			**$ 2.89**	**-$ 1.22**	**-29.65%**
HST		13%		$ 0.53	13%		$ 0.38	-$ 0.16	-29.65%
Total Bill (including HST)				$ 4.64			$ 3.26	-$ 1.37	-29.65%
Ontario Clean Energy Benefit [1]				-$ 0.46			-$ 0.33	$ 0.13	-28.26%
Total Bill on TOU (including OCEB)				**$ 4.18**			**$ 2.93**	**-$ 1.24**	**-29.80%**
Loss Factor (%)		4.47%			5.41%				

[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.

Appendix B – Rate Design

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Cost Allocation Results and Revenue Allocation

Cost Allocation Results

Customer Class Name	REVENUE ALLOCATION (sheet O1) Service Rev Req (row40)		Misc. Revenue (mi) (row19)		Base Rev Req		Rev2Cost Expenses %	CUSTOMER UNIT COST PER MONTH (sheet O2) Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment	Maximum Charge
Residential	1,058,601	59.31%	124,359	79.14%	934,242	57.40%	101.82%	$6.55	$9.99	$13.33	$13.33
General Service < 50 kW	252,470	14.15%	17,091	10.88%	235,379	14.46%	107.80%	$10.82	$15.42	$20.38	$20.38
General Service > 50 to 4999 kW	446,970	25.04%	11,564	7.36%	435,406	26.75%	87.44%	$7.79	$11.73	$26.50	$97.35
Unmetered Scattered Load	1,071	0.06%	95	0.06%	976	0.06%	104.37%	$5.81	$8.96	$12.11	$12.11
Sentinel Lighting	1,181	0.07%	100	0.06%	1,081	0.07%	147.00%	$0.28	$0.43	$2.99	$2.99
Street Lighting	24,527	1.37%	3,929	2.50%	20,598	1.27%	167.72%	$0.00	$0.01	$1.63	$1.63
TOTAL	**1,784,820**	**100.00%**	**157,138**	**100.00%**	**1,627,682**	**100.00%**					

Revenue Reallocation - Service Revenue Requirement

Customer Class Name	Base Revenue Requirement % Cost Allocation Results		Existing Rates		Proposed Allocation		Revenue Offsets %	$	Service Revenue Requirement $ Cost Allocation	Existing Rates	Rate Application
Residential	57.40%	934,241	58.58%	953,478	57.40%	934,242	79.14%	124,359	1,058,600	1,077,837	1,058,601
General Service < 50 kW	14.46%	235,379	15.67%	255,072	14.46%	235,379	10.88%	17,091	252,470	272,163	252,470
General Service > 50 to 4999 kW	26.75%	435,406	23.30%	379,264	26.75%	435,406	7.36%	11,564	446,970	390,828	446,970
Unmetered Scattered Load	0.06%	976	0.06%	1,023	0.06%	975	0.06%	95	1,071	1,118	1,070
Sentinel Lighting	0.07%	1,081	0.10%	1,635	0.07%	1,081	0.06%	100	1,181	1,735	1,181
Street Lighting	1.27%	20,598	2.29%	37,208	1.27%	20,598	2.50%	3,929	24,527	41,137	24,527
TOTAL		**1,627,680**		**1,627,680**	**100.00%**	**1,627,680**		**157,138**	**1,784,818**	**1,784,818**	**1,784,818**

Revenue to Cost Ratio Allocation

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Target Range Floor	Target Range Celiling
Residential	1.02	1.00	-0.02	0.85	1.15
General Service < 50 kW	1.08	1.00	-0.08	0.80	1.20
General Service > 50 to 4999 kW	0.87	1.00	0.13	0.80	1.20
Unmetered Scattered Load	1.04	1.00	-0.04	0.70	1.20
Sentinel Lighting	1.47	1.00	-0.47	0.70	1.20
Street Lighting	1.68	1.00	-0.68	0.70	1.20

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Rate Design

Cost Allocation Results

Customer Class Name	Cost Allocation - Minimum Fixed Rate (b) Rate	Fixed %	Variable %	Cost Allocation - Maximun Fixed Rate (b) Rate	Fixed %	Variable %
Residential	$6.55	41.65%	58.35%	$13.33	84.75%	15.25%
General Service < 50 kW	$10.82	34.97%	65.03%	$20.38	65.87%	34.13%
General Service > 50 to 4999 kW	$7.79	2.10%	97.90%	$97.35	26.29%	73.71%
Unmetered Scattered Load	$5.81	35.75%	64.25%	$12.11	74.51%	25.49%
Sentinel Lighting	$0.28	6.53%	93.47%	$2.99	69.70%	30.30%
Street Lighting	$0.00	0.00%	100.00%	$1.63	115.38%	-15.38%

Existing Rates

Customer Class Name	Current Rates and Split Rate	Fixed %	Variable %	Calculated Rates at Current Split Rate	Fixed %	Variable %
Residential	$5.99	45.09%	54.91%	$7.09	45.09%	54.91%
General Service < 50 kW	$13.84	49.88%	50.12%	$15.43	49.88%	50.12%
General Service > 50 to 4999 kW	$97.35	36.48%	63.52%	$135.05	36.48%	63.52%
Unmetered Scattered Load	$6.39	45.28%	54.72%	$7.36	45.28%	54.72%
Sentinel Lighting	$1.63	30.35%	69.65%	$1.30	30.35%	69.65%
Street Lighting	$0.62	29.36%	70.64%	$0.41	29.36%	70.64%

Rate Design

Customer Class Name	Proposed Fixed Charge Fixed Rate	Fixed %	Variable %	Resulting Variable Variable (h)	Rate (i)	per
Residential	$10.00	63.58%	36.42%	340,242	$0.0064	kWh
General Service < 50 kW	$15.00	48.48%	51.52%	121,259	$0.0063	kWh
General Service > 50 to 4999 kW	$97.35	26.29%	73.71%	434,445	$2.1601	kW
Unmetered Scattered Load	$8.50	52.30%	47.70%	465	$0.0021	kWh
Sentinel Lighting	$3.00	69.94%	30.06%	325	$1.1130	kW
Street Lighting	$1.00	70.78%	29.22%	6,018	$1.8742	kW
				902,754		

Customer Class Name	Transf. Allowance ($/kW): kW	Rate	($0.60) Total $ (g)	Base Revenue Requirement $ Total (d)	Fixed	Variable
Residential	0	$0.00	0	934,242	594,000	340,242
General Service < 50 kW	0	$0.00	0	235,379	114,120	121,259
General Service > 50 to 4999 kW	189,205	$0.60	113,523	435,406	114,484	320,922
Unmetered Scattered Load	0	$0.00	0	975	510	465
Sentinel Lighting	0	$0.00	0	1,081	756	325
Street Lighting	0	$0.00	0	20,598	14,580	6,018
				1,627,680	**838,450**	**789,231**

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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	$774,573	52%	$1,058,601	59.31%
GS < 50 kW	$211,822	14%	$252,470	14.15%
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$471,811	32%	$446,970	25.04%
GS > xxx kW, if applicable		0%		0.00%
Large User, if applicable		0%		0.00%
Street Lighting	$29,336	2%	$24,527	1.37%
Sentinel Lighting	$1,498	0%	$1,181	0.07%
Unmetered Scattered Load (USL)	$849	0%	$1,071	0.06%
Other class, if applicable		0%		0.00%
		0%		0.00%
Embedded distributor class		0%		0.00%
Total	$1,489,889	100%	$1,784,820	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	$934,241	$953,478	$934,242	$124,359
GS < 50 kW	$235,379	$255,072	$235,379	$17,091
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$435,406	$379,264	$435,406	$11,564
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$20,598	$37,208	$20,598	$3,929
Sentinel Lighting	$1,081	$1,635	$1,081	$100
Unmetered Scattered Load (USL)	$976	$1,023	$975	$95
Other class, if applicable				
Embedded distributor class				
Total	$1,627,680	$1,627,680	$1,627,680	$157,138

From CA Model

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	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 20XX	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	111.00	101.82	100.00	85 - 115
GS < 50 kW	111.00	107.80	100.00	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	80.00	87.44	100.00	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	70.00	167.72	100.00	70 - 120
Sentinel Lighting	120.00	146.95	100.00	80 - 120
Unmetered Scattered Load (USL)	80.00	104.41	99.92	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	100.00	96		85 - 115
GS < 50 kW	100.00	105		80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	100.00	105		80 - 120
GS > xxx kW, if applicable		100		80 - 120
Large User, if applicable				85 - 115
Street Lighting	100.00	120		70 - 120
Sentinel Lighting	100.00	120		80 - 120
Unmetered Scattered Load (USL)	99.92	100		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 entered as ‘Rebalance’.

Appendix 2-S
Stranded Meter Treatment
REVISED

Year	Notes	Gross Asset Value	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		$221,805.19	$95,458.19		$126,347.00		$126,347.00
2007		$222,885.19	$110,272.19		$112,613.00		$112,613.00
2008		$224,821.63	$125,119.63		$99,702.00		$99,702.00
2009		$246,912.13	$140,473.13		$106,439.00		$106,439.00
2010		$246,912.13	$156,129.13		$90,783.00		$90,783.00
2011		$246,912.13	$171,379.13		$75,533.00		$75,533.00
2012	(1)	$246,912.13	$183,817.13		$63,095.00		$63,095.00
2013		$246,912.13	$192,555.13		$54,357.00		**$54,357.00**

2011 acquisitions of $7,797 and 2012 acquisitions of $134.61 were removed from standed meters. They will remain in books as "Conventional Meters" in account 1860.000.

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TESI-9

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 1589)	Rate Rider for Deferral/Variance	
Residential	kWh	51,132,834	-$ 93,439	- **0.0018**	$/kWh
GS<50	kWh	18,531,353	-$ 26,923	- **0.0015**	$/kWh
GS>50	kW	206,640	-$ 36,222	- **0.1753**	$/kW
USL	kWh	214,901	$ 43	**0.0002**	$/kWh
Sentinel	kW	284	$ 56	**0.1970**	$/kW
Street Lights	kW	3,751	-$ 1,613	- **0.4301**	$/kW
		-	$ -	**-**	
Total			**-$ 158,098**		

Rate Rider Calculation for RSVA - Power - Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	Non-RPP kW / kWh / # of Customers	Balance of RSVA - Power - Global	Rate Rider for RSVA - Power -	
Residential	kWh	2,604,189	$ 8,639	**0.0033**	$/kWh
GS<50	kWh	70,374	$ 233	**0.0033**	$/kWh
GS>50	kW	206,640	$ 258,330	**1.2501**	$/kW
USL	kWh	9,584	$ 32	**0.0033**	$/kWh
Sentinel	kW	16	$ 19	**1.1955**	$/kW
Street Lights	kW	3,751	$ 4,498	**1.1991**	$/kW
		-	$ -	**-**	
Total			**$ 271,751**		

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) **1**

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and	Rate Rider for Accounts 1575 and	
Residential	kWh	51,132,834	-$ 8,620	- **0.0002**	$/kWh
GS<50	kWh	18,531,353	-$ 3,124	- **0.0002**	$/kWh
GS>50	kW	206,640	-$ 13,129	- **0.0635**	**$/kW**
USL	kWh	214,901	-$ 36	- **0.0002**	$/kWh
Sentinel	kW	284	-$ 17	- **0.0608**	**$/kW**
Street Lights	kW	3,751	-$ 229	- **0.0609**	**$/kW**
		-	$ -	**-**	
Total			**-$ 25,155**		

Appendix C –
CA sheet I7.2 meter reading
CA sheet I7.1 meter capital
CA sheet O1
CA sheet O2

2013 Cost Allocation Model

Sheet I7.1 Meter Capital Worksheet -

		Residential			GS <50			GS>50-Regular			Street Light			Sentinel			Unmetered Scattered Load			TOTAL		
		1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			62.48%			35%			2%			0%			0%			0%			100%
	Cost Relative to Residential Average Cost			1.00			4.57			13.47			-			-			-			1.42
	Total	4950	396,000	80	615	224,899	365.69	12	12,931	1077.583333	0	0	-	0	0	-	0	0	-	5577	633,830	113.650771
Meter Types	Cost per Meter (Installed)																					
Single Phase 200 Amp - Urban	80	0	-			0			0			0			0			0		0	-	
Single Phase 200 Amp - Rural	150	0	0			0			0			0			0			0		0	-	
Central Meter	250	0	0			0			0			0			0			0		0	-	
Network Meter (Costs to be updated)	225	0	0			0			0			0			0			0		0	-	
Three-phase - No demand	210	0	0		0	0			0			0			0			0		0	-	
Smart Meters	366	0	0		615	224,899			0			0			0			0		615	224,899	
Demand without IT (usually three-phase)	500	0	0		0	0			0			0			0			0		0	-	
Demand with IT	2,100		0			0			0			0			0			0		0	-	
Demand with IT and Interval Capability - Secondary	500		0			0			-			0			0			0		0	-	
Demand with IT and Interval Capability - Primary	10,000		0			0			0			0			0			0		0	0	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0			0			0			0		0	0	
Smart Meters	80	4,950	396,000		0	0			0		0	0		0	0		0	0		4,950	396000	
Smart Meters 3Phase Demand	500		0			0		10	5000			0			0			0		10	5000	
Meter Demand - 115KV Station IESO Metering	3,966		0			0		2	7931			0			0			0		2	7931	

Sheet I7.2 Meter Reading Worksheet -

Weighting Factors based on Contractor Pricing

Description	Factor	1 Residential Units	1 Residential Weighted Factor	1 Residential Weighted Average Costs	2 GS <50 Units	2 GS <50 Weighted Factor	2 GS <50 Weighted Average Costs	3 GS>50-Regular Units	3 GS>50-Regular Weighted Factor	3 GS>50-Regular Weighted Average Costs
Allocation Percentage Weighted Factor				71.16%			8.97%			19.87%
Cost Relative to Residential Average Cost				1.00			1.00			14.19
Total		4,878	32,023	6.56	615	4,037	6.56	96	8,940	93.12
Residential - Urban - Outside	1.00		0			0			0	
Residential - Urban - Outside with other services	1.00		0			0			0	
Residential - Urban - Inside	2.00		0			0			0	
Residential - Urban - Inside - with other services	1.00		0			0			0	
Residential - Rural - Outside	3.00		0			0			0	
Residential - Rural - Outside with other services	2.00		0			0			0	
Smart Meter	6.56	4,878	32,023		615	4,037			0	
Smart Meter with Demand	6.56		0			0		10	66	
GS - Walking	5.00		0		0	0		0	0	
GS - Walking - with other services	3.00		0			0			0	
GS - Vehicle with other services --- TOU Read	3.00		0			0			0	
GS - Vehicle with other services	3.00		0			0			0	
Conventional 3Phase Demand Meters	103.19		0			0		86	8,874	
LDC Specific 4			0			0			0	
Interval	0.00		0			0			0	
LDC Specific 5	49.00		0			0			0	
LDC Specific 6			0			0			0	

Description	7 Street Light Units	7 Street Light Weighted Factor	7 Street Light Weighted Average Costs	8 Sentinel Units	8 Sentinel Weighted Factor	8 Sentinel Weighted Average Costs	9 Unmetered Scattered Load Units	9 Unmetered Scattered Load Weighted Factor	9 Unmetered Scattered Load Weighted Average Costs	TOTAL Units	TOTAL Weighted Factor	TOTAL Weighted Average Costs
Allocation Percentage Weighted Factor			0.00%			0.00%			0.00%			100.00%
Cost Relative to Residential Average Cost			0.00			0.00			0.00			16.19
Total	-	-	0	-	-	0	-	-	0	5,589	45,000	106
Residential - Urban - Outside		0			0			0		-	-	
Residential - Urban - Outside with other services		0			0			0		-	-	
Residential - Urban - Inside		0			0			0		-	-	
Residential - Urban - Inside - with other services		0			0			0		-	-	
Residential - Rural - Outside		0			0			0		-	-	
Residential - Rural - Outside with other services		0			0			0		-	-	
Smart Meter		0			0			0		5,493	36,060	
Smart Meter with Demand		0			0			0		10	66	
GS - Walking		0			0			0		-	-	
GS - Walking - with other services		0			0			0		-	-	
GS - Vehicle with other services --- TOU Read		0			0			0		-	-	
GS - Vehicle with other services		0			0			0		-	-	
Conventional 3Phase Demand Meters		0			0			0		86	8,874	
LDC Specific 4		0			0			0		-	-	
Interval		0			0			0		-	-	
LDC Specific 5		0			0			0		-	-	
LDC Specific 6		0			0			0		-	-	

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet -

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

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	4	5	6	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue at Existing Rates	$1,347,014	$789,066	$211,089	$313,866	$0	$0	$0	$30,792	$1,353	$847
mi	Miscellaneous Revenue (mi)	$157,139	$124,359	$17,091	$11,564	$0	$0	$0	$3,929	$100	$95
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	$1,504,153	$913,425	$228,180	$325,430	$0	$0	$0	$34,722	$1,454	$942
	Factor required to recover deficiency (1 + D)	1.2084									
	Distribution Revenue at Status Quo Rates	$1,627,681	$953,478	$255,072	$379,264	$0	$0	$0	$37,208	$1,635	$1,023
	Miscellaneous Revenue (mi)	$157,139	$124,359	$17,091	$11,564	$0	$0	$0	$3,929	$100	$95
	Total Revenue at Status Quo Rates	$1,784,820	$1,077,837	$272,163	$390,828	$0	$0	$0	$41,138	$1,736	$1,118
	Expenses										
di	Distribution Costs (di)	$274,050	$133,182	$38,036	$92,620	$0	$0	$0	$9,634	$454	$125
cu	Customer Related Costs (cu)	$454,515	$388,923	$57,702	$7,402	$0	$0	$0	$70	$70	$348
ad	General and Administration (ad)	$398,100	$281,205	$52,522	$58,505	$0	$0	$0	$5,326	$285	$257
dep	Depreciation and Amortization (dep)	$222,217	$92,610	$38,560	$86,920	$0	$0	$0	$3,888	$136	$103
INPUT	PILs (INPUT)	$18,399	$6,866	$2,771	$8,505	$0	$0	$0	$237	$10	$10
INT	Interest	$162,523	$60,650	$24,475	$75,130	$0	$0	$0	$2,091	$88	$89
	Total Expenses	$1,529,804	$963,435	$214,066	$329,083	$0	$0	$0	$21,245	$1,043	$932
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$255,016	$95,166	$38,404	$117,887	$0	$0	$0	$3,282	$138	$139
	Revenue Requirement (includes NI)	$1,784,820	$1,058,601	$252,470	$446,970	$0	$0	$0	$24,527	$1,181	$1,071
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$5,893,610	$2,322,562	$897,986	$2,544,426	$0	$0	$0	$121,554	$4,120	$2,961
gp	General Plant - Gross	$1,467,651	$552,485	$218,509	$672,493	$0	$0	$0	$22,509	$870	$785
accum dep	Accumulated Depreciation	($2,287,667)	($965,136)	($361,120)	($892,145)	$0	$0	$0	($66,250)	($1,983)	($1,033)
co	Capital Contribution	($256,306)	($109,820)	($31,172)	($100,846)	$0	$0	$0	($14,013)	($361)	($95)
	Total Net Plant	$4,817,288	$1,800,091	$724,204	$2,223,929	$0	$0	$0	$63,801	$2,646	$2,618
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$16,429,254	$5,673,596	$2,040,295	$8,560,284	$0	$0	$0	$120,574	$11,100	$23,404
	OM&A Expenses	$1,126,665	$803,309	$148,260	$158,528	$0	$0	$0	$15,029	$808	$730
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$17,555,919*	*$6,476,906*	*$2,188,556*	*$8,718,811*	*$0*	*$0*	*$0*	*$135,604*	*$11,908*	*$24,135*
	Working Capital	$2,282,269	$841,998	$284,512	$1,133,445	$0	$0	$0	$17,628	$1,548	$3,138
	Total Rate Base	$7,099,557	$2,642,089	$1,008,716	$3,357,374	$0	$0	$0	$81,429	$4,194	$5,755
		Rate Base Input equals Output									
	Equity Component of Rate Base	$2,839,823	$1,056,836	$403,486	$1,342,950	$0	$0	$0	$32,572	$1,678	$2,302
	Net Income on Allocated Assets	$255,016	$114,402	$58,097	$61,745	$0	$0	$0	$19,892	$693	$186
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$255,016	$114,402	$58,097	$61,745	$0	$0	$0	$19,892	$693	$186
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	100.00%	101.82%	107.80%	87.44%	0.00%	0.00%	0.00%	167.72%	147.00%	104.37%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($280,667)	($145,176)	($24,290)	($121,540)	$0	$0	$0	$10,195	$273	($130)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$19,236	$19,693	($56,142)	$0	$0	$0	$16,611	$555	$47
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	10.82%	14.40%	4.60%	0.00%	0.00%	0.00%	61.07%	41.31%	8.07%

2013 Cost Allocation Model

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

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$6.55	$10.82	$7.79	$0.00	$0.28	$5.81
Customer Unit Cost per month - Directly Related	$9.99	$15.42	$11.73	$0.01	$0.43	$8.96
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.33	$20.38	$26.50	$1.55	$2.99	$12.11
Existing Approved Fixed Charge	$5.99	$13.84	$97.35	$0.62	$1.63	$6.39

Appendix D –
Power Supply Expense

Precedent: LoadForecast

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Power Supply Expense

Determination of Commodity

		Actual 3 Actual kWh's		
Customer Class Name		**Hist3 Actual kWh's**	**non-RPP**	**RPP**
Residential		51,132,834	2,604,189	48,528,645
General Service < 50 kW		18,531,354	70,374	18,460,980
General Service > 50 to 4999 kW		77,875,019	77,875,019	0
Unmetered Scattered Load		214,901	9,584	205,317
Sentinel Lighting		102,354	5,803	96,551
Street Lighting		1,355,855	1,355,855	0
TOTAL		**149,212,317**	**81,920,824**	**67,291,493**
%		*100.00%*	*54.90%*	*45.10%*

Forecast Price

HOEP ($/MWh)				$19.33		Note: Table ES-1 from current RPP report - Load Weighted price for RPP Consumers
Global Adjustment ($/MWh)				$66.12		Note: Table ES-1 from current RPP report - Impact of Global Adjustment
Adjustments						
TOTAL ($/MWh)				**$85.45**	**$83.95**	Note: Table ES-1 from current RPP report - Impact of Global Adjustment
$/kWh				***$0.08545***	***$0.08395***	
%				54.90%	45.10%	
WEIGHTED AVERAGE PRICE		**$0.0848**		**$0.0469**	**$0.0379**	

Electricity Projections

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	4006	4705	57,672,462	0.08069	$4,653,591	56,383,451	$0.08477	$4,779,824
General Service < 50 kW	kWh	4010	4705	21,217,841	0.08069	$1,712,068	20,276,186	$0.08477	$1,718,884
General Service > 50 to 4999 kW	kWh	4035	4705	87,194,930	0.08069	$7,035,759	85,070,970	$0.08477	$7,211,767
Unmetered Scattered Load	kWh	4010	4705	236,373	0.08069	$19,073	232,589	$0.08477	$19,717
Sentinel Lighting	kWh	4025	4705	112,104	0.08069	$9,046	110,310	$0.08477	$9,351
Street Lighting	kWh	4025	4705	1,212,731	0.08069	$97,855	1,198,252	$0.08477	$101,580
TOTAL				**167,646,440**		**$13,527,391**	**163,271,758**		**$13,841,124**

Transmission - Network

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4066	4714	57,672,462	0.0069	$397,940	56,383,451	0.0070	$394,457
General Service < 50 kW	kWh	4066	4714	21,217,841	0.0063	$133,672	20,276,186	0.0064	$129,517
General Service > 50 to 4999 kW	kW	4066	4714	206,144	2.5533	$526,347	201,122	2.5888	$520,668
Unmetered Scattered Load	kWh	4066	4714	236,373	0.0063	$1,489	232,589	0.0064	$1,486
Sentinel Lighting	kW	4066	4714	297	1.9264	$572	292	1.9532	$570
Street Lighting	kW	4066	4714	3,250	1.9258	$6,259	3,211	1.9526	$6,270
TOTAL				**79,336,366**		**$1,066,280**	**77,096,851**		**$1,052,968**

Transmission - Connection

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4068	4716	57,672,462	0.0031	$178,785	56,383,451	0.0032	$178,536
General Service < 50 kW	kWh	4068	4716	21,217,841	0.0027	$57,288	20,276,186	0.0028	$55,919
General Service > 50 to 4999 kW	kW	4068	4716	206,144	1.1197	$230,819	201,122	1.1437	$230,025
Unmetered Scattered Load	kWh	4068	4716	236,373	0.0027	$638	232,589	0.0028	$641
Sentinel Lighting	kW	4068	4716	297	1.7674	$525	292	1.8053	$527
Street Lighting	kW	4068	4716	3,250	0.8656	$2,813	3,211	0.8842	$2,839
TOTAL		**0**	**0**	**79,336,366**		**$470,869**	**77,096,851**		**$468,488**

Wholesale Market Service

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**	**0.0052**		**rate ($/kWh):**	**0.0052**
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4708	57,672,462	0.00440	$253,759	56,383,451	0.00440	$248,087
General Service < 50 kW	kWh	4062	4708	21,217,841	0.00440	$93,359	20,276,186	0.00440	$89,215
General Service > 50 to 4999 kW	kWh	4062	4708	87,194,930	0.00440	$383,658	85,070,970	0.00440	$374,312
Unmetered Scattered Load	kWh	4062	4708	236,373	0.00440	$1,040	232,589	0.00440	$1,023
Sentinel Lighting	kWh	4062	4708	112,104	0.00440	$493	110,310	0.00440	$485
Street Lighting	kWh	4062	4708	1,212,731	0.00440	$5,336	1,198,252	0.00440	$5,272
TOTAL		**0**	**0**	**167,646,440**		**$737,644**	**163,271,758**		**$718,396**

Rural Rate Protection

Precedent: LoadForecast

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Power Supply Expense

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4730	57,672,462	0.00120	$69,207	56,383,451	0.00120	$67,660
General Service < 50 kW	kWh	4062	4730	21,217,841	0.00120	$25,461	20,276,186	0.00120	$24,331
General Service > 50 to 4999 kW	kWh	4062	4730	87,194,930	0.00120	$104,634	85,070,970	0.00120	$102,085
Unmetered Scattered Load	kWh	4062	4730	236,373	0.00120	$284	232,589	0.00120	$279
Sentinel Lighting	kWh	4062	4730	112,104	0.00120	$135	110,310	0.00120	$132
Street Lighting	kWh	4062	4730	1,212,731	0.00120	$1,455	1,198,252	0.00120	$1,438
TOTAL		**0**	**0**	**167,646,440**		**$201,176**	**163,271,758**		**$195,926**

Smart Meter Entity Charge

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	Cust						4,905	0.79000	$46,499
General Service < 50 kW	Cust						630	0.79000	$5,972
General Service > 50 to 4999 kW	Cust						96	0.79000	$910
Unmetered Scattered Load	Cust						5	0.79000	$47
Sentinel Lighting	Cust						21	0.79000	$199
Street Lighting	Cust						1,210		
TOTAL							**6,867**		**$53,628**

Low Voltage Charges

	Current Low Voltage Rates		2013 PROJECTED TRANSMISSION-CONNECTION REVENUE				
Customer Class Name	**Rate**	**per**	**Rate**	**per**	**Uplifted Volumes**	**Revenue**	**%**
Residential	$0.0004	kWh	**$0.0032**	kWh	56,383,451	$178,536	38.11%
General Service < 50 kW	$0.0004	kWh	**$0.0028**	kWh	20,276,186	$55,919	11.94%
General Service > 50 to 4999 kW	$0.1369	kW	**$1.1437**	kW	201,122	$230,025	49.10%
Unmetered Scattered Load	$0.0004	kWh	**$0.0028**	kWh	232,589	$641	0.14%
Sentinel Lighting	$0.2162	kW	**$1.8053**	kW	292	$527	0.11%
Street Lighting	$0.1059	kW	**$0.8842**	kW	3,211	$2,839	0.61%
TOTAL	**0**	**0**		**$0**	**77,096,851**	**$468,488**	**100%**

Low Voltage Charges
(not loss adjusted)

	2014 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	38.11%	37,955	53,488,924	$0.0007	kWh
General Service < 50 kW	11.94%	11,888	19,235,278	$0.0006	kWh
General Service > 50 to 4999 kW	49.10%	48,900	201,122	$0.2431	kW
Unmetered Scattered Load	0.14%	136	220,649	$0.0006	kWh
Sentinel Lighting	0.11%	112	292	$0.3838	kW
Street Lighting	0.61%	604	3,211	$0.1880	kW
TOTAL	**100.00%**	**99,595**	**73,149,476**		

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**		**2013**			**2014**	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	54,711,762	$0.0004	$21,885	53,488,924	$0.0007	$37,442.25
General Service < 50 kW	kWh	4075	4750	20,128,592	$0.0004	$8,051	19,235,278	$0.0006	$11,541.17
General Service > 50 to 4999 kW	kW	4075	4750	206,144	$0.1369	$28,221	201,122	$0.2431	$48,892.76
Unmetered Scattered Load	kWh	4075	4750	224,238	$0.0004	$90	220,649	$0.0006	$132.39
Sentinel Lighting	kW	4075	4750	297	$0.2162	$64	292	$0.3838	$112.07
Street Lighting	kW	4075	4750	3,250	$0.1059	$344	3,211	$0.1880	$603.67
TOTAL		**0**	**0**	**75,274,283**		**$58,655**	**73,149,476**		**$98,724.30**

Projected Power Supply Expense					**$16,062,015**			**$16,429,254**