Sioux Lookout Hydro Inc.
P.O. Box 908, 25 Fifth Ave.
Sioux Lookout, ON P8T 1B3
Tel: (807)737-3800
Fax: (807)737-2832
Email: slhydro@tbaytel.net

May 3, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor – 2300 Yonge Street
Toronto, ON M4P 1E4

Re: Sioux Lookout Hydro Inc. - 2013 Cost of Service Electricity Distribution Rate Application
EB-2012-0165
Written Responses to Interrogatories

Dear Ms. Walli:

Please find enclosed Sioux Lookout Hydro Inc.'s (SLHI) written responses to interrogatories as filed by Board Staff, Vulnerable Energy Consumers Coalition (VECC), and Mr. Doug Shields.

These responses are being filed pursuant to the Board's e-Filing Services. Two hard copies of the responses will be delivered to the Board via registered mail. In addition, one electronic copy will be forwarded to all intervenors listed above.

Also attached please find the following:

- LFCDMAWF_Sioux_Lookout_Hydro_20130418_Completed
- Sioux Lookout_2013_EDDVAR_Continuity Schedule_CoS_V2_updated _20130501
- Sioux Lookout_2013_Rev_Reqt_Work_form_V3_20130501
- SiouxLookout_Filing_Requirements_Chapter2_Appendices_V1.1_updated_20130501
- Sioux Lookout_IRR_9Staff28
- Sioux Lookout_RolledUp_CA_Model_Run#1_20130501

An electronic version of these responses has been submitted through the e-Filing Services.

If you require any further information, please do not hesitate to contact me at (807)737-3800 or via email at dkulchyski@tbaytel.net.

Sincerely,

Deanne Kulchyski, CGA, BComm(Hons)
President/CEO

Sioux Lookout Hydro Inc.

2013 Electricity Distribution Rates

Written Response to Interrogatories

EB-2012-0165

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GENERAL INTERROGATORIES

0-Staff-1

It would appear that certain data have been inconsistently stated in the application such that it is unclear which values SLHI is relying on and what the appropriate resultant rates should be.

If in addressing these interrogatories and those of VECC and Mr. Shields, any inconsistent data is found which affects the rates requested, please file a complete consistent set of models, worksheets, data, etc. covering all key aspects of the application, in a manner that reflects the Board's current policies, guidelines, etc.

SLHI Response

SLHI agrees to file complete consistent sets of models, worksheets, data etc. as requested if inconsistencies are found.

0-Staff-2

Following publication of the Notice of Application, has SLHI received any letters of comment in respect of this application? If so, please confirm whether a reply was sent by SLHI in response to such comments and if so, please file copies of such responses with the Board. If not, please explain why a response was not sent and advise whether SLHI intends to respond and file a copy of the response it and when such response is given.

SLHI Response

SLHI did not receive any letters of comments, therefore no replies were required.

0-Staff-3

Taking into account responses from interrogatories from Board staff and intervenors, please provide an updated RRWF with any necessary corrections or adjustments that SLHI wishes to make to the amounts in the previous version of the RRWF, included in the middle column, without making any changes to the left column ("Initial Application") which reflects the initial application. Please include a reference to the correction or adjustment such as an interrogatory response or an explanatory note.

SLHI Response

SLHI has filed an updated RRWF with changes made for the cost of power, updated asset figures based on actual 2012 capital expenditures and cost of capital. References to the adjustments are included in the spreadsheet.

0-VECC-1

a) Please provide a tracking sheet (table) showing all adjustments arising from the interrogatories (include Reference IR #; item description; area of change, i.e. return on capital/rate base/working capital allowance/amortization/PILS/OM&A/etc.)
b) Please update the RRWF Excel Live spread sheet for all interrogatory adjustments.

SLHI Response

a) SLHI has provided a tracking sheet included as Appendix A.

b) SLHI has filed the RRWF Excel Live spreadsheet as requested.

0-Staff-4

Ref: Appendix 2-W

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption/demand levels (i.e. 800 kWh for residential, 2,000 kWh for GS < 50).

SLHI Response

SLHI has provided an updated Appendix 2-W for all classes at the typical consumption/demand levels as Appendix B.

0-Shields-1

What amounts of money were turned over to the Town each year in the past six years?

SLHI Response

See below for a summary of the dividends paid to the Municipality of Sioux Lookout in the past six years. Please note that the amount paid was for the dividend declared for the prior year.

Year	**Dividend Paid**
2012	$250,000
2011	$212,956
2010	$239,000
2009	$185,000
2008	$130,000
2007	$285,158

Also, in 2007 an amount of $1,226,489 was paid to the Municipality as a result of a directive from the Shareholder to restructure the debt/equity of the corporation. In order to do this Sioux Lookout Hydro incurred additional debt and reduced share capital.

0-Shields-2

When was the last delivery charge increase and what was the amount?

SLHI Response

The last delivery charge increase was effective September 1, 2012. This was a result of the Application for Recovery of Costs Related to Smart Meter Deployment (EB-2012-0245). The amount of the increase for the residential customer was $7.03 per month.

This increase is made up of a rate rider of $2.42 to recover the difference between the deferred revenue requirement for the installed smart meters up to the date of disposition and the smart meter revenue collected through funding adders from our customer and associated interest. The rate rider is effective until August 31, 2014. The remaining $4.61 is a smart meter incremental revenue requirement rate rider which will be in effect until the date of our 2013 cost of service application rate order.

0-Shields-3

Why does Sioux lookout Hydro charge more for the time of day rates in contrast to Hydro One in Dryden? Sioux Lookout Hydro has a 1.0642 multiplier for each time of day rate.

SLHI Response

The time-of-use rates are set by the Ontario Energy Board twice a year, May 1st and November 1st. The rates per kWh are the same across the entire province. The 1.0642 multiplier you are referring to is the adjustment for line loss approved in our last cost of service application in 2008. This factor is specific to each LDC. Line loss is explained on the back of your bill under Electricity as follows:

"*The electricity consumed is multiplied by the adjustment factor*.*"

*"*When electricity is delivered over a power line, it is normal for a small amount of power to be consumed or lost as heat. Equipment, such as wires and transformers, consumes power before it gets to your home or business. The adjustment factor accounts for these losses."*

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Staff-5

Ref: Exhibit 1/Tab 1/Sch. 16/p. 1

a) Please identify any rates and charges that are included in SLHI’s conditions of service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.

b) If applicable, please provide a schedule outlining the revenues recovered from these rates and charges from SLHI’s last rate re-basing year 2008 to 2011 and the revenue forecasted for the 2012 bridge and 2013 test years.

c) If applicable, please explain whether in SLHI’s view, these rates and charges should be included on SLHI’s tariff sheet.

SLHI Response

a) SLHI’s conditions of service includes a list of construction development fees for underground and overhead found in Schedules 2 through 4 which are not on the Board-approved tariff sheet. The fees are based on 2007 actual costs for the materials listed and associated overhead costs.

b) SLHI does not earn any revenue from these charges.

c) SLHI feels that these rates and charges should not be included on SLHI’s tariff sheet as they are charges related to contributed capital and are based on actual costs of materials.

EXHIBIT 2 – RATE BASE

2-Staff-6

Ref: Exhibit 2/Tab 3/Sch. 1 & 2

SLHI provides details of its capital expenditures in the 2007-2012 period.

Please provide a table that compares the approved capital expenditures (i.e. OEB approved or SLHI's Board of Directors approved) and the subsequent actual capital expenditures for each year in the 2007 to 2012 period and provide an explanation for the differences. The information should be provided on an account basis.

SLHI Response

Capital Expenditure Comparison - 2007 to 2012																		
	2007			2008			2009			2010			2011			2012		
Account	SLHI Board Approved	Actual	*Variance*	OEB Approved	Actual	*Variance*	SLHI Board Approved	Actual	*Variance*	SLHI Board Approved	Actual	*Variance*	SLHI Board Approved	Actual	*Variance*	SLHI Board Approved	Actual	*Variance*
1830	249,000	180,302	-68,698	213,000	157,373	-55,627	90,000	172,714	82,714	207,765	198,775	-8,990	205,000	165,064	-39,936	42,935	182,302	139,367
1835			0			0			0	2,000	810	-1,190			0	18,038	8,295	-9,743
1840			0	5,000	7,589	2,589	5,000	2,608	-2,392	2,000	1,739	-261	5,000	5,944	944	5,000	5,031	31
1845	35,000	52,496	17,496	20,000	54,030	34,030	45,000	35,314	-9,686	50,000	27,838	-22,162	60,000	53,964	-6,036	15,003	22,723	7,720
1850	35,000	60,135	25,135		133,674	133,674		6,590	6,590	70,000	68,869	-1,131	85,000	62,129	-22,871	74,749	88,816	14,067
1860	65,000	2,014	-62,986		2,047	2,047	40,000	95,936	55,936	60,000	57,207	-2,793	10,000	6,478	-3,522	3,360	11,628	8,268
1920	2,000		-2,000		1,753	1,753	26,000	25,810	-190	2,000	320	-1,680	2,000	2,337	337	8,500	8,394	-106
1925	0	2,090	2,090		2,160	2,160			0	1,000	2,295	1,295	1,000	22,500	21,500	0	0	0
1915	2,000	1,094	-906		1,652	1,652	1,000	4,659	3,659	4,000	356	-3,644	4,000	3,798	-202	5,000	6,000	1,000
1930	0		0	80,000	68,430	-11,570		31,183	31,183	0		0	0		0	150,000	35,425	-114,575
1940	5,000	3,991	-1,009	5,000	6,177	1,177	5,000	4,984	-16	5,000	1,130	-3,870	5,000	2,436	-2,564	5,000	4,626	-374
1945	3,000		-3,000	3,000	873	-2,127	3,000		-3,000	3,000		-3,000	3,000		-3,000	3,000		-3,000
1950	0		0		1,690	1,690	100,000	4,215	-95,785	0	23,400	23,400	0		0	0	720	720
1955	2,000	7,819	5,819	2,000	1,268	-732	2,000	2,155	155	2,000	0	-2,000	2,000		-2,000	2,000	1,235	-765
1985	2,000	2,070		2,000	1,408	-592	2,000	1,810	-190	2,000	1,425	-575	2,000	1,169	-831	0	1,752	1,752
WIP					3,512	3,512		-1,221	-1,221		26,301	26,301		-8,090	-8,090		-6,723	-6,723
Sub-total	**400,000**	**312,011**	***-88,059***	**330,000**	**443,636**	***113,636***	**319,000**	**386,757**	***67,757***	**410,765**	**410,465**	***-300***	**384,000**	**317,729**	***-66,271***	**332,585**	**370,226**	***37,641***
Contributions & Grants																		
1995		-50,141			-83,680			-96,209			-112,799			-73,975			-84,053	
Total		261,870			359,956			290,548			297,666			243,754			286,173	

<u>Variance Explanations:</u>

Year	Account	Variance Explanation
2007	1830	SLHI did not perform any work on the Mill Line upgrade in 2007. Amount budgeted for this job was $100,000
2007	1845	$15,000 of this variance is due to amounts included in contributions and grants.
2007	1850	Includes the cost of $17,000 for a transformer which was recovered through contributed capital.
2007	1860	SLHI budgeted $50,000 for the purchase of smart meters in 2007 which was not needed.
2008	1830	The Mill Line upgrade was budgeted for again in 2008, but due to the closure of the mill was postponed for an indefinite period.
2008	1845	$40,000 of this is due to capital contributions for underground driven by

		customer demand throughout the year
2008	1850	$35,000 of this variance is due to amounts recovered through contributed capital. The balance is due to a higher number of new transformers required to be installed for new services in our rural territory. SLHI notes that the 2008 budget did not include any amounts for transformers for unknown reasons.
2008	1930	The actual cost of a new truck was less than budgeted.
2009	1830	Mainly due to costs for a new subdivision and overspending on the pole replacement program by $30,000
2009	1860	Includes approximately $42,000 for the purchase and installation of smart meters for GS > 50 customers.
2009	1930	Purchased a new ½ ton truck in lieu of the new Power operated equipment budgeted for.
2009	1950	SLHI budgeted for the purchase of new equipment that was put on hold.
2010	1845	Less than anticipated new underground services
2010	1950	Purchased a float trailer not included in the budget.
2011	1830	Moosehorn Road voltage upgrade budgeted for was started late, therefore most of the work was done in 2012.
2011	1850	Lower customer demand for new transformers than budgeted
2011	1925	Purchased mapping software that was not budgeted
2012	1830	Combination of Moosehorn Road upgrade under budgeted for 2012, and higher than forecasted customer demand projects that required line work.
2012	1850	Purchased a spare transformer for approximately $17,000 that was not budgeted for.
2012	1930	The cost of the Line truck overhaul/betterment was lower than forecasted.

2-Staff-7

Ref: Exhibit 2/Tab 3/Sch. 2/p. 24

SLHI states that an analysis of the costs and benefits of continuing to contract out tree trimming/line clearing work, compared to those of purchasing a new backhoe with attached brush hog at a cost of $86,000, indicated that the latter option was more cost effective.

a) Please provide details of the costs and benefit analysis for the expected life of the backhoe. Please include all assumptions supporting this analysis.

SLHI Response

a) See below for a table comparing the costs for the purchase of the brush hog vs. Contracting out line clearing/tree trimming work over the life of the brush hog:

Cost Benefit Analysis - Backhoe Purchase				
	Backhoe Purchase	**Contractor fees**	**Yearly Savings/(Costs)**	**Cumulative Savings/(Costs)**
Costs				
One-Time Capital Costs	$ (86,000)	$ -	$ (86,000)	$ (86,000)
On-going Costs				
Year 1				
Amortization	$ (10,750)			
Maintenance	$ (300)	$ (30,000)		
Operational	$ (3,950)			
Total Costs Year 1	**$ (15,000)**	**$ (30,000)**	**$ 15,000**	**$ (71,000)**
Year 2				
Amortization	$ (10,750)			
Maintenance	$ (300)	$ (30,600)		
Operational	$ (4,029)			
Total Costs Year 2	**$ (15,079)**	**$ (30,600)**	**$ 15,521**	**$ (55,479)**
Year 3				
Amortization	$ (10,750)			
Maintenance	$ (550)	$ (31,212)		
Operational	$ (4,110)			
Total Costs Year 3	**$ (15,410)**	**$ (31,212)**	**$ 15,802**	**$ (39,677)**
Year 4				
Amortization	$ (10,750)			
Maintenance	$ (920)	$ (31,836)		
Operational	$ (4,192)			
Total Costs Year 4	**$ (15,862)**	**$ (31,836)**	**$ 15,974**	**$ (23,702)**
Year 5				
Amortization	$ (10,750)			
Maintenance	$ (1,060)	$ (32,473)		
Operational	$ (4,276)			
Total Costs Year 5	**$ (16,086)**	**$ (32,473)**	**$ 16,387**	**$ (7,315)**
Year 6				
Amortization	$ (10,750)			
Maintenance	$ (1,160)	$ (33,122)		
Operational	$ (4,361)			
Total Costs Year 6	**$ (16,271)**	**$ (33,122)**	**$ 16,851**	**$ 9,537**
Year 7				
Amortization	$ (10,750)			
Maintenance	$ (1,440)	$ (33,785)		
Operational	$ (4,448)			
Total Costs Year 7	**$ (16,638)**	**$ (33,785)**	**$ 17,147**	**$ 26,683**
Year 8				
Amortization	$ (10,750)			
Maintenance	$ (1,540)	$ (34,461)		
Operational	$ (4,537)			
Total Costs Year 8	**$ (16,827)**	**$ (34,461)**	**$ 17,633**	**$ 44,316**
Assumptions:				
50 spans of line per year to be cleared				
Non-incremental labour costs not included				
2% inflation factor				

The analysis indicates that the cost of the brush hog would be recovered through savings achieved by not contracting out the work by year 6. Keeping up with tree trimming is essential in SLHI's service territory because there are significant areas with dense foliage. Keeping lines clear of trees aids in the reduction of power outages due to tree contact caused by adverse weather conditions.

Additional benefits of the purchase include the ability of the brush hog to enter into areas which are inaccessible to trucks and performing operations such as setting/straightening poles, as well as trenching and installing anchors. There is also a benefit to our human resources, as the brush hog will eliminate the risk of physical injuries if the work were to be done with a chainsaw, and long term ergonomic injuries (i.e. back injuries) associated with performing the work manually.

2-VECC-2

Reference: Exhibit 2, Tab 3, Schedule 1, pg. 1

a) Please confirm that there are no streetlight assets included in the 2012 and 2013 continuity schedules.

SLHI Response

a) SLHI confirms that there are no streetlight assets included in the 2012 and 2013 continuity schedules.

2-VECC-3

Reference: Exhibit 2, Tab 3, Schedule 2, pg. 18

a) If Table 2.17 – 2012 Capital Budget – is a forecast, then please update the Table for the 2012 actuals (unaudited if audited not available).

b) Please update Appendix 2-A (Excel Spreadsheet Chapter2_Appendices_V1.1_20130304) for actual 2012 project completions.

c) Please update Table 2.18 – 2013 Capital Budget – and Appendix 2-A for any changes in the 2013 capital budget due to actual 2012 project completions.

SLHI Response

a) Below is Table 2.17 updated to the 2012 actual capital:

Table 2.17- 2012 Actual Capital Projects (MCGAAP)

Distribution Plant (Projects > $50,000 materiality threshold)								
Category	**Reference Number**	**Total**	**Poles (1830)**	**OH Conductor (1835)**	**Conduit (1840)**	**UG Conductor (1845)**	**Transformers (1850)**	**Meters (1860)**
Reliability	3	8,259	8,259					
Reliability	23	72,127	68,320	459	979		2,369	
Customer Demand	30	150,824	59,700	2,451	4,052	18,311	54,682	11,628
		0						
Subtotal		**231,211**	**136,279**	**2,910**	**5,031**	**18,311**	**57,051**	**11,628**
Contributed Capital (1995)		-84,053	-6,728			-18,898	-54,164	-4,263
Subtotal		**147,158**	**129,551**	**2,910**	**5,031**	**-587**	**2,887**	**7,365**
Projects < $50,000		**87,586**	46,023	5,385		4,412	31,765	
Total Distribution Plant		**234,743**						

General Plant (Projects > $50,000 materiality threshold)											
Category	**Reference Number**	**Total**	**Office Equipment (1915)**	**Computer Equipment (1920)**	**Computer Equipment (1925)**	**Transportation Equipment (1930)**	**Tools, Shop and Garage (1940)**	**Measuring and Testing (1945)**	**Power Operated Equipment (1950)**	**Communication Equipment (1955)**	**Sentinel Lighting Rentals (1985)**
Line Truck Betterment	35	35,425				35,425					
Subtotal		**35,425**	**0**	**0**	**0**	**35,425**	**0**	**0**	**0**	**0**	**0**
Projects < $50,000		**22,727**	6,000	8,394	0		4,626		720	1,235	1,752
Total General Plant		**58,153**									
Total Capital 2012		**292,896**									

b) The updated Appendix 2-A is shown below and is included in the Excel Spreadsheet Sioux Lookout_Filing_Requirements_Chapter2_Appendices_V1.1_updated_20130501 attached to this submission.

Appendix 2-A
Capital Projects Table

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Overhead							
Airport 3 Phase Extension	4,671						
Blue Heron Subdivision			16,968				
Friesen pole line					17,912		
General Upgrades						26,195	7,490
Golf Course Subdivision					1,286		
Government Row Upgrade	5,213	3,047					
Hostel	24,203	19,127	326				
Hwy 72 South	4,877	18,372	1,845	61,582	3,033	8,259	
Meno Ya Win	1,373	3,078	2,818				
Moosehorn Rd Voltage Upgrade					18,689	68,780	
New Connections	13,997	11,707	15,260	13,719	12,906	62,151	6,929
Pole Replacement Program	125,969	104,030	134,275	122,818	116,167	25,213	46,922
Sturgeon Road Upgrade					13,769		
Sub-Total	180,302	159,361	171,493	198,120	183,763	190,598	61,341
Underground							
Ameresco							
Finway							
General Upgrades						4,412	1,736
Golf Course Subdivision				17,688	12,921		
Hostel		10,704					
Meno Ya Win			9,128				
Moosehorn Rd Voltage Upgrade					979	979	
New Connections	52,496	50,916	28,794	29,577	29,299	22,363	20,216
Sturgeon River Submarine Cable							72,200
Sub-Total	52,496	61,620	37,922	47,265	43,199	27,754	94,152
Transformers							
Airport Transformer Replacement					15,090		
Golf Course Subdivision				10,079			
Hostel	17,833	1,523					
Hwy 72 South				20,155			
New Connections	42,302	133,674	6,590	48,714	36,960	54,682	29,613
Spare Transformer						17,215	
Upgrades/Replacements						14,550	30,154
Moosehorn Rd Voltage Upgrade						2,369	
Sub-Total	60,135	135,197	6,590	78,948	52,050	88,816	59,767
Meters							
Hostel			2,052				
Meno Ya Win			35,019				
MNR Central Metering				50,668	3,109		
New Connections	2,014	2,047		6,539	3,369	11,628	1,680
Smart Meters for GS > 50 kW			58,865				
Sub-Total	2,014	2,047	95,936	57,207	6,478	11,628	1,680
Vehicles							
2008 Ford F-S/Duty		68,430					
2010 Chev			31,183				
Line Truck Betterment						35,425	
Sub-Total	0	68,430	31,183	0	0	35,425	0
Power Operated Equipment							
Backhoe							86,000
Nodwell Trailer				23,400			
Sub-Total	0	0	0	23,400	0	0	86,000
Computer Hardware/Software							
Asset Management Software			21,865				
Mapping Software					22,500		
Security System						5,381	
Sub-Total	0	0	21,865	0	22,500	5,381	0
Miscellaneous	17,064	16,981	21,768	5,526	9,740	17,346	17,000
Contributed Capital	-50,141	-83,680	-96,209	-112,799	-73,975	-84,053	-92,000
Total	**261,871**	**359,956**	**290,548**	**297,666**	**243,754**	**292,895**	**227,940**

c) No changes were made to the 2013 Capital Budget as a result of actual 2012 project completions.

2-VECC-4

Reference: Exhibit 2, Tab 2, Schedule 1, pg. 6-8

a) Please update the 2012 and 2013 Fixed Asset Continuity Statements for actual 2012 assets (Tables 2.6 and 2.7)

SLHI Response

a) See below for the updated 2012 and 2013 Fixed Asset continuity Statements, Tables 2.6 and 2.7 for 2012 actuals.

Table 2.6: Fixed Asset Continuity Statement – 2012 (MCGAAP)

Year 2012 -Bridg MCGAAP

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 29,045	$ 50,740		$ 79,785	$ 4,805	$ 39,401		$ 44,206	$ 35,579
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 91,864			$ 91,864	$ 41,024	$ 3,675		$ 44,699	$ 47,165
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 3,473,474	$ 182,302		$ 3,655,776	$ 1,186,272	$ 55,418		$ 1,241,690	$ 2,414,087
47	1835	Overhead Conductors & Devices		$ 1,079,982	$ 8,295		$ 1,088,277	$ 474,889	$ 17,873		$ 492,762	$ 595,515
47	1840	Underground Conduit		$ 173,392	$ 5,031		$ 178,423	$ 68,108	$ 2,392		$ 70,500	$ 107,923
47	1845	Underground Conductors & Devices		$ 887,702	$ 22,723		$ 910,425	$ 305,490	$ 16,937		$ 322,427	$ 587,997
47	1850	Line Transformers		$ 1,607,741	$ 88,816		$ 1,696,557	$ 587,436	$ 30,868		$ 618,304	$ 1,078,254
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 454,082	$ 8,138	-$ 294,462	$ 167,758	$ 126,510	$ 11,818	-$ 112,869	$ 25,459	$ 142,299
47	1860	Meters (Smart Meters)		$ -	$ 647,486		$ 647,486	$ -	$ 147,661		$ 147,661	$ 499,825
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 17,532	$ 6,000	-$ 1,791	$ 21,741	$ 8,429	$ 1,539	-$ 1,791	$ 8,176	$ 13,565
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 41,661	$ 28,977	-$ 1,753	$ 68,885	$ 28,983	$ 14,056	-$ 1,753	$ 41,286	$ 27,599
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 347,546	$ 35,425		$ 382,971	$ 312,619	$ 8,923		$ 321,541	$ 61,430
10	1930	Transportation Equipment(5 years)		$ 90,317			$ 90,317	$ 72,128	$ 6,237		$ 78,365	$ 11,952
8	1940	Tools, Shop & Garage Equipment		$ 67,211	$ 17,556		$ 84,767	$ 51,258	$ 7,433		$ 58,691	$ 26,076
8	1945	Measurement & Testing Equipment		$ 12,694			$ 12,694	$ 9,474	$ 1,087		$ 10,561	$ 2,133
8	1950	Power Operated Equipment		$ 135,802	$ 720		$ 136,522	$ 113,113	$ 3,852		$ 116,965	$ 19,557
8	1955	Communications Equipment		$ 37,334	$ 1,235		$ 38,569	$ 30,354	$ 1,595		$ 31,949	$ 6,620
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ 27,688	$ 1,752		$ 29,440	$ 20,977	$ 1,221		$ 22,198	$ 7,242
47	1995	Contributions & Grants		-$ 891,191	-$ 84,053		-$ 975,244	-$ 209,723	-$ 22,039		-$ 231,762	-$ 743,482
WIP		Work In Progress		$ 20,502	-$ 6,723		$ 13,779	$ -			$ -	$ 13,779
		Total		**$ 7,704,378**	**$ 1,014,421**	**-$ 298,006**	**$ 8,420,793**	**$ 3,232,145**	**$ 349,947**	**-$ 116,413**	**$ 3,465,679**	**$ 4,947,872**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 19,012
Tools/Sentinel Lights	$ 11,336
Net Depreciation	$ 319,599

Table 2.7: Fixed Asset Continuity Statement – 2013 Test (MCGAAP)

Year 2013 - Test MCGAAP

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 79,785	$ 1,000		$ 80,785	$ 44,206	$ 15,207		$ 59,413	$ 21,372
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 91,864			$ 91,864	$ 44,699	$ 3,675		$ 48,374	$ 43,490
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 3,655,776	$ 49,073		$ 3,704,849	$ 1,241,690	$ 71,867		$ 1,313,557	$ 2,391,293
47	1835	Overhead Conductors & Devices		$ 1,088,277	$ 12,268		$ 1,100,545	$ 492,762	$ 18,117		$ 510,879	$ 589,666
47	1840	Underground Conduit		$ 178,423	$ 5,000		$ 183,423	$ 70,500	$ 2,850		$ 73,351	$ 110,073
47	1845	Underground Conductors & Devices		$ 910,425	$ 89,152		$ 999,577	$ 322,427	$ 21,759		$ 344,186	$ 655,391
47	1850	Line Transformers		$ 1,696,557	$ 59,767		$ 1,756,324	$ 618,304	$ 38,150		$ 656,454	$ 1,099,870
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 167,758			$ 167,758	$ 25,459	$ 12,205		$ 37,664	$ 130,094
47	1860	Meters (Smart Meters)		$ 647,486	$ 1,680		$ 649,166	$ 147,661	$ 43,222		$ 190,883	$ 458,283
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 21,741			$ 21,741	$ 8,176	$ 1,851		$ 10,027	$ 11,714
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 68,885	$ 2,000		$ 70,885	$ 41,286	$ 9,630		$ 50,917	$ 19,968
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 382,971			$ 382,971	$ 321,541	$ 12,982		$ 334,523	$ 48,448
10	1930	Transportation Equipment(5 years)		$ 90,317			$ 90,317	$ 78,365	$ 6,237		$ 84,602	$ 5,715
8	1940	Tools, Shop & Garage Equipment		$ 84,767	$ 5,000		$ 89,767	$ 58,691	$ 8,037		$ 66,728	$ 23,039
8	1945	Measurement & Testing Equipment		$ 12,694	$ 7,000		$ 19,694	$ 10,561	$ 1,293		$ 11,854	$ 7,840
8	1950	Power Operated Equipment		$ 136,522	$ 86,000		$ 222,522	$ 116,965	$ 14,662		$ 131,627	$ 90,895
8	1955	Communications Equipment		$ 38,569			$ 38,569	$ 31,949	$ 1,627		$ 33,577	$ 4,992
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ 29,440	$ 2,000		$ 31,440	$ 22,198	$ 1,466		$ 23,664	$ 7,776
47	1995	Contributions & Grants		-$ 975,244	-$ 92,000		-$ 1,067,244	-$ 231,762	-$ 31,278		-$ 263,040	-$ 804,204
WIP		Work In Progress		$ 13,779			$ 13,779	$ -			$ -	$ 13,779
		Total		**$ 8,420,793**	**$ 227,940**	**$ -**	**$ 8,648,733**	**$ 3,465,679**	**$ 253,562**	**$ -**	**$ 3,719,241**	**$ 4,921,716**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 33,881
Tools/Sentinel Lights	$ 12,424
Net Depreciation	$ 207,257

2-VECC-5

Reference: Exhibit 2, Tab 3, Schedule 2, Pg. 23

a) Please provide the expected capital contribution for the 2013 Project #40 – Sturgeon River Submarine Cable. If no contribution was sought please explain why not.

b) The evidence states Ontario Hydro (Hydro One) installed the original cable. When did the customer become a ratepayer of SLHI? What conditions, compensation or other agreements were made between Hydro One and SLHI when this customer was transferred to the local utility.

c) What rate class is this customer?

SLHI Response

a) The expected capital contribution for the 2013 Project #40 – Sturgeon River Submarine Cable is estimated to be $46,000.

b) This customer became a rate payer of SLHI at the end of 1998 when the Municipality amalgamated with the Drayton Township. SLHI is not aware of any agreements or compensation made between Hydro One and SLHI when this customer was transferred.

c) The customer is classified as GS < 50.

2-Staff-8

Ref: Exhibit 2/Tab 3/Sch. 1/p.2, Exhibit 2/Tab 3/Sch. 2/p. 22 and Exhibit 2/Tab 3/Sch. 3/p. 2

With respect to the test year 2013, SLHI states in Tables 2.11 and 2.18 that the total capital expenditure net of contributions is projected at $227,940, and the capital contributions is projected at $92,000, totalling to a total capital expenditure forecast of $319,940.

Board staff notes that in Table 2.30, SLHI states that the total capital expenditure forecast is $317,941.

a) Please reconcile the total capital expenditure forecast provided in Tables 2.11 and 2.18 with Table 2.30.

SLHI Response

a) Tables 2.11 and 2.18 include an amount of $2,000 budgeted for sentinel lights which is not included in Table 2.30. The sentinel lights are included in all of the continuity schedules, but removed from the rate base.

2-VECC-6

Reference: Exhibit 2, Tab 3, Schedule 3

a) Table 2.30 which shows the 2013 Capital expenditure forecast from the Asset Management plan (also shown in Table 10, pg. 22 of the Asset Management Plan) is significantly higher ($317,941) then the proposed forecast ($227,940). Please explain the difference.

SLHI Response

a) Table 2.30 does not include contributed capital of $(92,000), or sentinel light additions of $2,000, which are included in the proposed forecast of $227,940.($317,941 - $92,000 + $2,000 = $227,941)

2-VECC-7

Reference: Exhibit 2, Tab 3, Schedule 3/Exhibit 4, Tab 2, Schedule 1, pg. 4

a) SLHI states it does monthly billing. The most recent Lead-Lag studies from Utilities who also use monthly billing have shown a working capital allowance requirement on between 11 and 12% (See London Hydro EB-2012-0380). Please explain why it would not be appropriate to use a lower working capital allowance given SLHI bills monthly.

SLHI Response

a) SLHI opted to use the Board approved default working capital allowance of 13% as set out in the Board's letter dated April 12, 2012. The effort and costs required to perform a lead lag study was not deemed to exceed the benefit of determining SLHI's utility specific working capital allowance.

2-Staff-9

Ref: Exhibit 2/Tab 4/Sch. 1/p. 2-5

Board staff notes that on March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that effective May 1, 2013, the:

- Rural or Remote Electricity Rate Protection ("RRRP) used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour; and
- Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour.

Board staff further notes that on March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211-0067) establishing a Smart Metering Entity ("SME") charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual Yearbook of Electricity Distributors. This charge will be in effect from May 1, 2013 to October 31, 2018.

a) Please update the Cost of Power, Working Capital Allowance and Rate Base using the updated values of RRRP and WMS.
b) Does SLHI believe that this new charge should be included in the Cost of Power Calculation for the purpose of determining the Working Capital Allowance?

SLHI Response

a) See below for the updated 2013 Cost of Power calculation:

2013 Load Forecast	kWh	kW	2011 % RPP
Residential	34,980,266		95%
General Service < 50 kW	12,526,981		99%
General Service 50 to 4,999 kW	25,251,296	63705.98685	9%
Street Lighting	499,759	1506.732846	2%
Unmetered Scattered Load	11,962		100%
Total	**73,270,262**	**65,213**	

Electricity - Commodity RPP	2013	2013 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2013**		
Residential	33,231,252	1.0897	36,212,096	0.08069	$2,921,954
General Service < 50 kW	12,401,711	1.0897	13,514,144	0.08069	$1,090,456
General Service 50 to 4,999 kW	2,272,617	1.0897	2,476,470	0.08069	$199,826
Street Lighting	9,995	1.0897	10,892	0.08069	$879
Unmetered Scattered Load	11,962	1.0897	13,035	0.08069	$1,052
Total	**47,927,537**		**52,226,637**		**$4,214,167**

Electricity - Commodity Non-RPP	2013	2013 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2013**		
Residential	1,749,013	1.0897	1,905,900	0.08134	$155,026
General Service < 50 kW	125,270	1.0897	136,507	0.08134	$11,103
General Service 50 to 4,999 kW	22,978,679	1.0897	25,039,867	0.08134	$2,036,743
Street Lighting	489,763	1.0897	533,695	0.08134	$43,411
Unmetered Scattered Load	0	1.0897	0	0.08134	$0
Total	**25,342,726**		**27,615,968**		**$2,246,283**

Transmission - Network		Volume			
Class per Load Forecast RPP		**Metric**	**2013**		
Residential		kWh	38,117,996	0.0065	$247,767
General Service < 50 kW		kWh	13,650,651	0.0059	$80,539
General Service 50 to 4,999 kW		kW	63705.98685	2.3692	$150,932
Street Lighting		kW	1506.732846	1.7868	$2,692
Unmetered Scattered Load		kWh	13,035	0.0059	$77
Total					**$482,007**

Transmission - Connection		Volume			
Class per Load Forecast RPP		**Metric**	**2013**		
Residential		kWh	38,117,996	0.0015	$57,177
General Service < 50 kW		kWh	13,650,651	0.0012	$16,381
General Service 50 to 4,999 kW		kW	63705.98685	0.5163	$32,891
Street Lighting		kW	1506.732846	0.3992	$601
Unmetered Scattered Load		kWh	13,035	0.0012	$16
Total					**$107,066**

Wholesale Market Service		Volume			
Class per Load Forecast RPP		**Metric**	**2013**		
Residential		kWh	38,117,996	0.0044	$167,719
General Service < 50 kW		kWh	13,650,651	0.0044	$60,063
General Service 50 to 4,999 kW		kWh	27516336.86	0.0044	$121,072
Street Lighting		kWh	544586.9227	0.0044	$2,396
Unmetered Scattered Load		kWh	13,035	0.0044	$57
Total					**$351,307**

Rural Rate Assistance		Volume			
Class per Load Forecast RPP		**Metric**	**2013**		
Residential		kWh	38,117,996	0.0012	$45,742
General Service < 50 kW		kWh	13,650,651	0.0012	$16,381
General Service 50 to 4,999 kW		kWh	27516336.86	0.0012	$33,020
Street Lighting		kWh	544586.9227	0.0012	$654
Unmetered Scattered Load		kWh	13,035	0.0012	$16
Total					**$95,811**

Low Voltage Charges		Volume			
Class per Load Forecast RPP		**Metric**	**2013**		
Residential		kWh	34,980,266	0.003435719	$120,182
General Service < 50 kW		kWh	12,526,981	0.003070217	$38,461
General Service 50 to 4,999 kW		kW	63705.98685	1.4169	$90,265
Street Lighting		kW	1506.732846	0.9531	$1,436
Unmetered Scattered Load		kWh	11,962	0.0031	$37
Total					**$250,381**

	2013
4705-Power Purchased	$6,460,450
4708-Charges-WMS	$351,307
4714-Charges-NW	$482,007
4716-Charges-CN	$107,066
4730-Rural Rate Assistance	$95,811
4750-LV Charges	$250,381
Total	**$7,747,023**

b) Based on the 2013 forecasted customer counts for Residential and GS < 50 customers, the SME charge would increase the cost of power by approximately $25,570 per year (2697*.79*12) bringing it to $7,772,593. ($7,747,023 + $25,570). SLHI believes it would be appropriate to include it in the calculation for the purpose of determining the working capital allowance.

The working capital allowance and rate base are updated with the new RRRP and WMS rates as well as the inclusion of the SME charge in the updated RRWF entitled Sioux Lookout_2013_Rev_Reqt_Work_Form_V3_20130501.

2-Staff-10

Ref: Exhibit 2/Tab 3/Sch. 5/p. 1 and Exhibit 2/Appendix 2-D

Board staff notes that SLHI's reliability indicators SAIDI, SAIFI and CAIDI (excluding loss of supply) as shown in the table below have steadily increased year-over-year during the period 2009 to 2011.

	Reliability Indicators (excluding Loss of Supply)		
Year	SAIDI	SAIFI	*CAIDI*
2009	0.32	0.33	.99
2010	0.90	0.56	1.60
2011	1.71	0.77	2.23

a) Please provide an explanation for the decrease in reliability as demonstrated by the steady increase in the reliability indicators.

b) Please explain what corrective actions, it any, SLHI plans to undertake to reverse this trend.

SLHI Response

a) The table presented below in interrogatory 2-VECC-8 shows that the customer hours of interruptions for 2011, 2010 and 2009 due to weather/lightning related outages was 74%, 51% and 43% respectively. The frequency of outages is similarly shown in this table and for the years 2011, 2010, and 2009 the percentage of outages related to weather and lightning was 63%, 55% and 42% respectively. In 2012 the number of weather/lightning related outages decreased to 33% for duration and 36% for frequency, thus the indicators for SAIDI and SAIFI for 2012 are significantly lower.

b) The 2012 Reliability Indicators (excluding loss of supply) are:
   - SAIDI: 0.47
   - SAIFI: 0.17
   - CAIDI: 2.77

   The statistics collected indicate that weather is a dominant factor in these reliability statistics, as explained in a). SLHI continues to perform scheduled outages for repairs and upgrades in order to improve reliability. Also, the purchase of the brush hog will enable SLHI to perform more tree trimming in less time in order to reduce the amount outages due to tree contact. Another measure SLHI is taking to reduce the number of outages is to install bird guards on our transformers. The spring and fall show increased outages caused by birds landing on transformers.

2-VECC-8

Reference: Exhibit 2, Appendix 2-A, Table 4, pg. 7/Exhibit 2, Appendix 2-D

a) Please update Table 4 to show 2012 SAIFI, SAIDI, and CAIDI statistics with and without supply loss.

b) Please fill out the attached table (or similar table which SLHI may use internally) which shows the causes of outages.

Description	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Scheduled				
Supply Loss				
Tree Contact				
Lightning				
Def. Equip.(other than pole)				
Pole Failure				
Weather				
Human Element				
Animals, Vehicle				
Environment				
Unknown				
Total				

SLHI Response

a) See below for the 2012 SAIDI, SAIFI and CAIDI statistics:

SERVICE RELIABILITY INDICES EXCLUDING OUTAGES CAUSED BY LOSS OF SUPPLY

2012	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1)/(3)	SAIFI (5) (2)/(3)	CAIDI (4)/(5)
Jan	3	3	2757	0.00	0.00	1.00
Feb	6	6	2745	0.00	0.00	1.00
Mar	57	31	2752	0.02	0.01	1.84
Apr	44	47	2745	0.02	0.02	0.94
May	12	5	2760	0.00	0.00	2.40
Jun	94	72	2765	0.03	0.03	1.31
Jul	44	21	2765	0.02	0.01	2.10
Aug	297	144	2783	0.11	0.05	2.06
Sep	554	71	2777	0.20	0.03	7.80
Oct	75	16	2769	0.03	0.01	4.69
Nov	29	18	2769	0.01	0.01	1.61
Dec	75	32	2766	0.03	0.01	2.34
Annual Total	1290	466	2763	0.47	0.17	2.77

SERVICE RELIABILITY INDICES INCLUDING OUTAGES CAUSED BY LOSS OF SUPPLY

2012	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1)/(3)	SAIFI (5) (2)/(3)	CAIDI (4)/(5)
Jan	3	3	2757	0.00	0.00	1.00
Feb	6	6	2745	0.00	0.00	1.00
Mar	57	31	2752	0.02	0.01	1.84
Apr	44	47	2745	0.02	0.02	0.94
May	12	5	2760	0.00	0.00	2.40
Jun	94	72	2765	0.03	0.03	1.31
Jul	44	21	2765	0.02	0.01	2.10
Aug	483	2927	2783	0.17	1.05	0.17
Sep	554	71	2777	0.20	0.03	7.80
Oct	75	16	2769	0.03	0.01	4.69
Nov	29	18	2769	0.01	0.01	1.61
Dec	75	32	2766	0.03	0.01	2.34
Annual Total	1476	3249	2763	0.53	1.18	0.45

b) The causes of outages are shown in the Table below. SLHI included outages relating to lightning, weather and tree contact in the same category up to 2012. For 2013 we are tracking these separately. Also the scheduled outages for 2012 include outages required for the Moosehorn Rd voltage upgrade.

Description	2009 Total Customer Hours of Interruptions	% (excl loss of supply)	2009 Total Customer Interruptions	% (excl loss of supply)	2010 Total Customer Hours of Interruptions	% (excl loss of supply)	2010 Total Customer Interruptions	% (excl loss of supply)	2011 Total Customer Hours of Interruptions	% (excl loss of supply)	2011 Total Customer Interruptions	% (excl loss of supply)	2012 Total Customer Hours of Interruptions	% (excl loss of supply)	2012 Total Customer Interruptions	% (excl loss of supply)
Scheduled	353.77	42%	224	25%	732.58	28%	206	13%	322.9	7%	132	6%	565.22	44%	85	18%
Supply Loss					27499.34		8210		16585.84		2746		185.53		2783	
Tree Contact																
De. Equip. (other than pole)	37.34	4%	98	11%	315.76	12%	203	13%	505.75	11%	269	13%	95.55	7%	44	9%
Pole failure																
Weather/Lightning	363.56	43%	374	42%	1324.18	51%	879	55%	3316.47	74%	1333	63%	427.58	33%	170	36%
Human Element	8.42	1%	1	0%	59.17	2%	38	2%	0							
Animals, Vehicle	42.66	5%	150	17%	15.43	1%	117	7%	152.67	3%	178	8%	99.08	8%	97	21%
Environment																
Unknown	45.85	5%	51	6%	174.58	7%	145	9%	196.72	4%	192	9%	94.95	7%	73	16%
Total excluding loss of supply	**851.6**	**100%**	**898**	100%	**2621.7**	**100%**	**1588**	100%	**4494.51**	**100%**	**2104**	100%	**1282.38**	**100%**	**469**	**100%**
Total	**851.6**		**898**		**30121.04**		**9798**		**21080.35**		**4850**		**1467.91**		**3252**	

2-VECC-9

Reference: Exhibit 2, Appendix 2-A, Table 4, pg. 7

a) At page 28 of the Asset Management plan it identifies the need for IT investments. However, the 2013 capital budget appears to have no new computer hardware or software investments. Please explain the discrepancy?

SLHI Response

a) SLHI did invest in a new mapping system in 2011, at a cost of 22,500 as well as an asset management software in 2009 at a cost of $25,000. This represents SLHI's commitment to improving its processes for monitoring and identifying areas which require future investments. SLHI did not identify any new IT assets that would be needed in 2013.

2-VECC-10

Reference: Exhibit 2, Tab 6, Schedule 1, pg. 1/Exhibit 2, Appendix 2-B

a) Please provide the capital and OM&A (separately) costs of the GEA plan for 2012 through 2013

SLHI Response

a) SLHI does not have any capital or OM&A costs relating to the GEA Plan for 2012 or 2013.

EXHIBIT 3 – OPERATING REVENUE

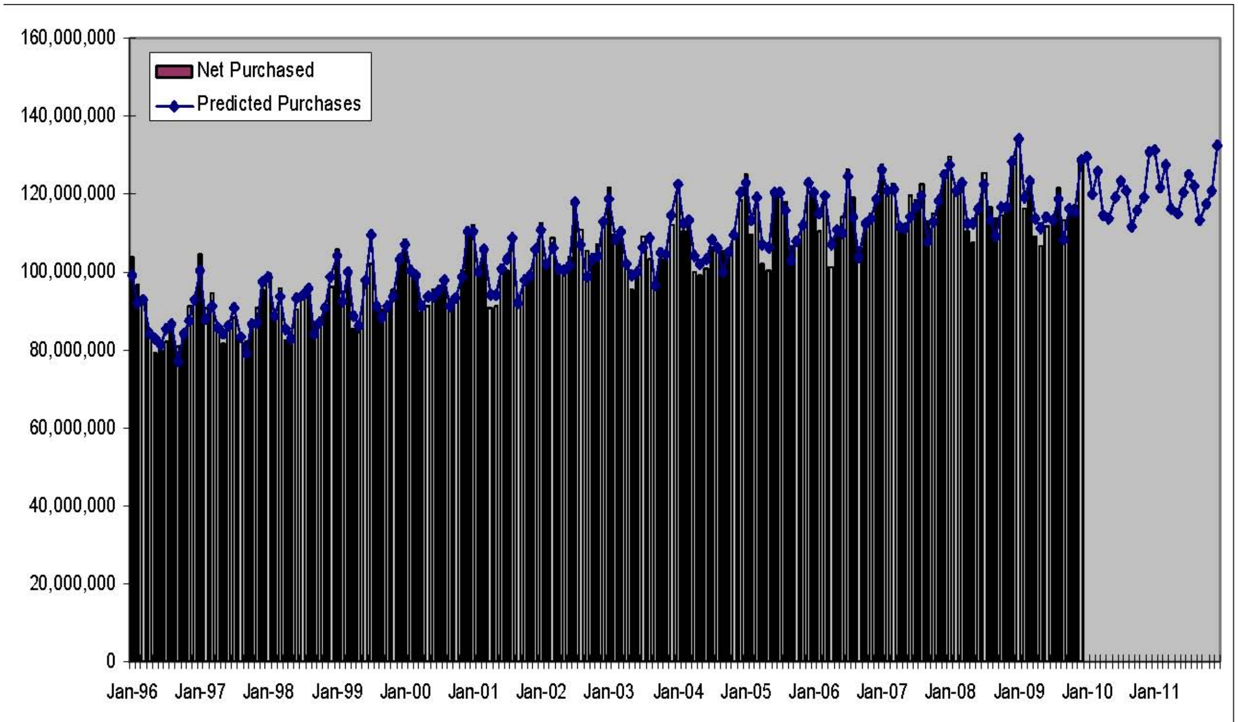
3-Staff-11

Ref: Exhibit 3/Tab 2/Sch. 1

a) Table 3.5 provides a summary statistics for the purchased power regression model. The table shows that the intercept, with an estimated value of 38,179, has a t-statistic of 0, and thus is statistically insignificant. Please explain why the intercept was retained given its statistical insignificance.

b) Was a variable to account for CDM tried? If so, please provide a general description of the variable and the results, and explain why the variable was not retained. If no CDM variable was tried, please provide an explanation.

c) Please provide a version of the chart showing the actual and predicted values, comparable to that shown on Exhibit 3/Tab 2/Sch. 1/p.9, but showing monthly data in a format similar to the following. Include 2012 actuals in the chart if available.



d) Please provide the Mean Absolute Percentage Error from the chart in c) based on the monthly residuals.

SLHI Response

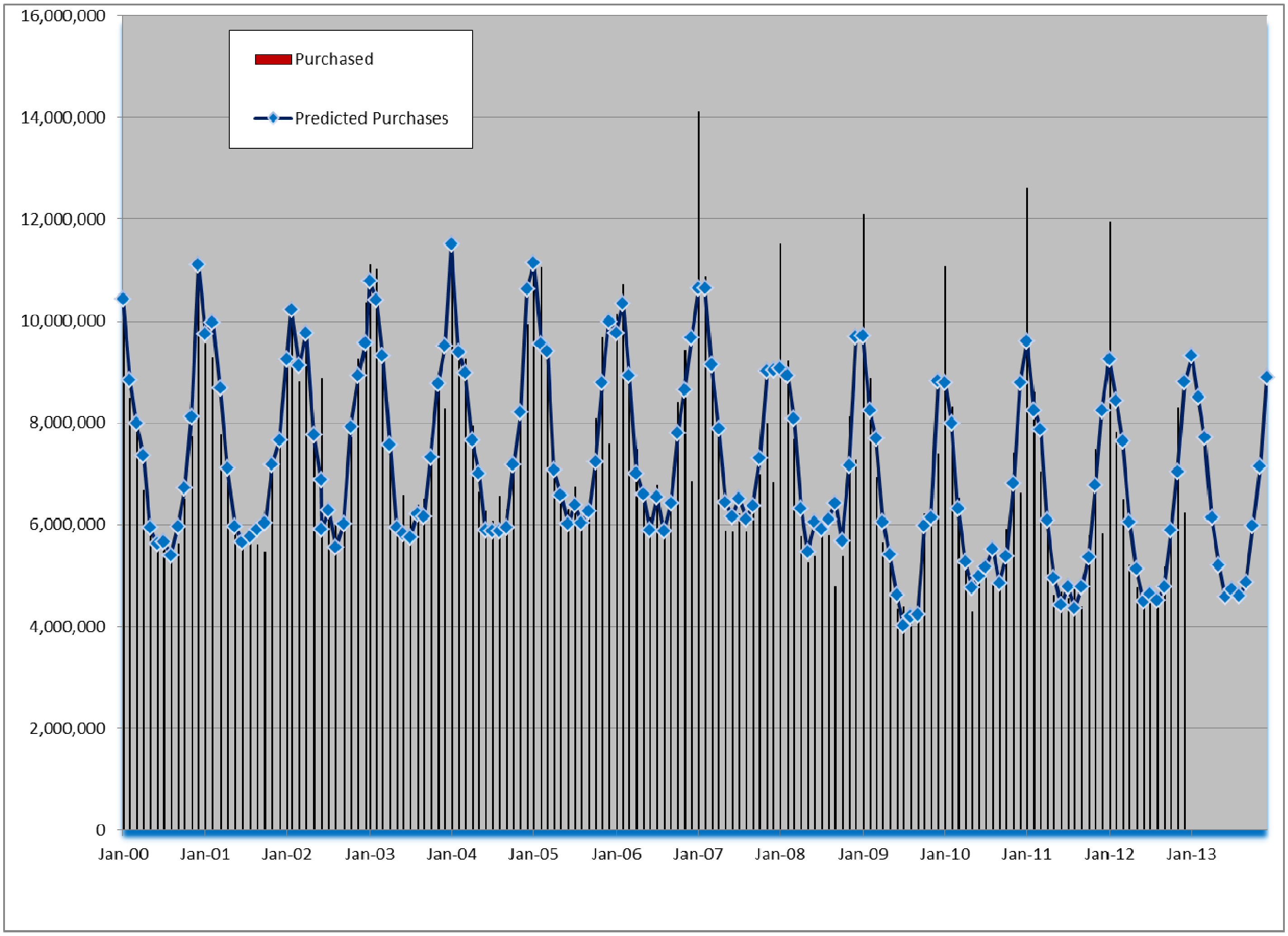
a) The intercept is assigned by the regression analysis used in Excel. In the Excel regression function the user has the option to set the intercept to zero. However, when the intercept is included the total of the residuals (i.e. the difference between the predicted and actual power purchase amount) over the regression period always equals zero which allows a check to ensure the predicted values are in line with the actual amounts. When the intercept is set to zero the residuals do not add to zero which causes an important checking mechanism to be eliminated.

In addition, when the intercept is set to zero the R-square value is 99% and the adjusted R-square value is 98%. The t-statistic of all variables is greater than the absolute value of 2. Sioux Lookout Hydro is concerned that the regression results appear to be "too good to be true" considering the R-square value is 82% and the adjusted R-square value is 81% in the regression analysis used in the application. The significant improvement in the statistical results, with the elimination of the intercept, causes Sioux Lookout Hydro to be somewhat apprehensive that it might be missing something that could cause the results to be invalid.

Based on the above discussion, Sioux Lookout Hydro believes it is a better practise to include the intercept at all times since it allows an important checking mechanism and the resulting statistics are reasonable.

b) Yes, a CDM activity variable to account for CDM was tried. The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values grow at constant value over the year. For the years 2006 to 2013, the addition of the monthly CDM activity values shown will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for Sioux Lookout Hydro. These values reflect the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include final results from 2011 programs that contribute to the four year licensed CDM kWh target assigned to Sioux Lookout Hydro. The CDM activity variable was not retained as it did not prove to be statistical significant.

c) The chart showing the actual and predicted values, comparable to that shown on Exhibit 3/Tab 2/Sch. 1/p.9, but showing monthly data including 2012 actuals is shown below.



d) The Mean Absolute Percentage Error from the chart in c) based on the monthly residuals from January 2000 to December 2011 is 7.1%

3-VECC-11

Reference: Exhibit 3, Tab 2, Schedule 1, pages 7-10

a) Is the 2011 Fall update the most recent publication available from the Ontario Ministry of Finance with actual forecast GDP data for 2011-2013?

b) If a more recent Outlook and Fiscal Review update is available please provide a schedule contrasting the Ontario Real GDP growth rates for 2011, 2012 and 2013 used in the Application with the more current information.

c) If there is updated information, please update both the regression model using the new 2011 data and the forecasts for 2012 and 2013 using the new GDP forecasts.

SLHI Response

a) The 2011 Fall update is not the most recent publication available from the Ontario Ministry of Finance with actual and forecast GDP data for 2011-2013. The 2012 Fall update is the most recent publication available.

b) A schedule contrasting, on an annual basis, the Ontario Real GDP growth rates for 2011, 2012 and 2013 used in the Application with the more current information is provided below.

	Application	Update
2011	1.8%	2.1%
2012	1.8%	2.0%
2013	2.5%	1.9%

c) The following provides both the results of the regression model using the new 2011 data and the power purchased forecasts for 2012 and 2013 using the new GDP forecasts.

Statistics		
R Square	81.5%	
Adjusted R Square	81.0%	
F Test	153.2	
Variable	Coefficients	T-stat
Intercept	54,607	0.03
Heating Degree Days	5,119	20.69
Cooling Degree Days	10,959	2.82
Ontario Real GDP Monthly %	26,274	2.27
Pulp Mill Flag	1,728,899	8.72
2012 Power Purchased Forecast (GWh)		76.8
2013 Power Purchased Forecast (GWh)		77.7

3-VECC-12

Reference: Exhibit 3, Tab 2, Schedule 1, pages 7-10

a) Please re-estimate the regression model and provide the results per Table 3.5 but instead of using total purchases, use total purchases less sales to the pulp mill as the variable to be explained and exclude the “Pulp Mill Flag” as an explanatory variable. (Note: For the purposes of this exercise please use the same data as was used to estimate the regression equation in the Application)

b) Based on the results for part (a) please provide a forecast for 2012 and 2013 purchases using the same forecast for the independent variables as in the Application.

SLHI Response

a) The regression model has been re-estimated and the table below provides the regression results per Table 3.5 but instead of using total purchases, total purchases are reduced by the sales to the pulp mill at the wholesale level. This means the pulp mill sales have been increased for losses. The "Purchases minus Pulp Mill" variable is explained by using the same data as was used to estimate the regression equation in the Application but the "Pulp Mill Flag" has been excluded. However, the regression analysis is conducted over the period July 2000 to December 2011 since prior to July 2000 consumption data for the Pulp Mill is not available.

b) The resulting forecast for 2012 and 2013 purchases is also provided in the table.

Statistics		
R Square	79.7%	
Adjusted R Square	79.3%	
F Test	175.9	
MAPE (Mean Absolute Percent Error) on Annual Value	1.6%	
Variable	Coefficients	T-stat
Intercept	31,379	0.02
Heating Degree Days	4,814	19.58
Cooling Degree Days	10,610	2.78
Ontario Real GDP Monthly %	26,518	2.57
2012 Power Purchased Forecast (GWh)		75.0
2013 Power Purchased Forecast (GWh)		76.0

3-Staff-12

Ref: Exhibit 3/Tab 2/Sch. 1/p. 11-12

Tables 3-7 and 3-9 show the number of USL connections declining from 13 in 2009 to 9 in 2010, 3 in 2011 and then 2 in each of 2012 and 2013.

a) Please explain the decline in USL connections.

SLHI Response

a) The decline in USL connections is a result of installing meters for these loads. Ten (10) of the connections are for cable boxes. Four (4) of these were metered in 2010, with the remaining six (6) converted in 2011. Of the remaining three (3) USLs, two (2) connections were metered in 2012, leaving only one (1) USL connection in 2013. SLHI believes changing the forecast of USL connections from two to one for the purpose of rate setting would not yield a material difference.

3-VECC-13

Reference: Exhibit 3, Tab 2, Schedule 1, page 11

a) Please provide the actual 2012 year-end customer count and average 2012 customer count for each rate class

SLHI Response

a) See below for a table illustrating the 2012 year-end customer count and average 2012 customer count for each rate class:

Rate Class	2012 Year End Customer/Connection Count	Average 2012 Customer/Connection Count
Residential	2312	2316
GS < 50 kW	391	386
GS 50 to 4,999 kW	51	51
Street Lighting	532	532
USL	1	2
Total	3287	3287

3-VECC-14

Reference: Exhibit 3, Tab 2, Schedule 1, page 15

a) Please provide a copy of the OPA's final 2011 CDM Report for SLHI.

SLHI Response

The OPA's final 2011 CDM report for SLHI is provided as Appendix 4-D in Exhibit 4 and the excel file was included as evidence in the original application.

3-Staff-13

Ref: Exhibit 3/Tab 2/Sch. 1, Exhibit 4/Appendix 4-D

SLHI has proposed to use a CDM target incorporating actual results for 2011 CDM programs as reported by the OPA as the starting point for the CDM adjustment for the 2013 load forecast amount to take into account the persistence of 2011 and 2012 CDM programs, and the impact of 2013 CDM programs on 2013 demand (consumption, measured in kWh). This is documented in Table 3-15.

SLHI's approach is to take into account the 2011 results and their persistence, as per the OPA report filed in Exhibit 4/Appendix 4-D, and then to assume an equal increment for each 2012, 2013, and 2014 so as to achieve SLHI's CDM target of 3,320,000 kWh. Board staff views that this approach is preferable, It provides results on what the utility has achieved to date, and sets out what more will be needed to achieve the cumulative four-year target. In using the measured and reported results from the 2011 programs, including the persistence into 2013, Board staff views that an improved estimate of the CDM impact of 2011-2013 programs on the LRAMVA threshold for 2013 (and 2014) would result, along with the corresponding adjustment to the 2013 test year load forecast.

Based on the final 2011 OPA results provided in Exhibit 4/Appendix 4-D, Board staff has prepared the following table, which is also provided in working Microsoft Excel format:

Load Forecast CDM Adjustment Work Form (2013)					
Sioux Lookout Hydro Inc.			***EB-2012-0165***		
4 Year (2011-2014) kWh Target:					
3,320,000					
	2011	2012	2013	2014	Total
%					
2011 CDM Programs	1.85%	1.85%	1.85%	1.84%	7.40%
2012 CDM Programs		15.43%	15.43%	15.43%	46.30%
2013 CDM Programs			15.43%	15.43%	30.87%
2014 CDM Programs				15.43%	15.43%
Total in Year	**1.85%**	**17.29%**	**32.72%**	**48.14%**	**100.00%**
kWh					
2011 CDM Programs	61,496	61,496	61,496	61,229	245,717
2012 CDM Programs		512,380	512,380	512,380	1,537,141
2013 CDM Programs			512,380	512,380	1,024,761
2014 CDM Programs				512,380	512,380
Total in Year	**61,496**	**573,877**	**1,086,257**	**1,598,370**	**3,320,000**
				Check	3,320,000
Net-to-Gross Conversion					
		"Gross"	**"Net"**	**Difference**	**"Net-to-Gross" Conversion Factor ('g')**
2006 to 2011 OPA CDM programs: Persistence to 2013		1	1	0	0.00%
	2011	**2012**	**2013**	**2014**	**Total for 2013**
Amount used for CDM threshold for LRAMVA	61,496	512,380	512,380		1,086,257
Manual Adjustment for 2013 Load Forecast	61,496	512,380	256,190		830,067
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)			*Only 50% of 2013 CDM impact is used based on a half year rule*		

The methodology for this is as follows:

For the top table:

- The 2011-2014 CDM target is input into cell B6;
- Measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 are input into cells C15 to F15; and
- Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

Board staff believes that this corresponds with Table 3-15.

The second table is to calculate the conversion from “net” to “gross” results. While the LRAMVA is based on the “net” OPA-reported results, the load forecast is impacted also by CDM savings of “free riders” and “free drivers”. While Board staff has input values of “1” in each of cells D26 to E26, in the absence of information, these should be populated with the measured “gross” and “net” CDM savings for the persistence of all CDM programs from 2006 to 2011 on 2013, as reported in the final OPA reports.

For the last table, two numbers are calculated:

- The “Amount used for CDM threshold for LRAMVA” is the sum of the persistence of 2011 and 2012 CDM programs and the annualized impact of 2013 CDM programs on 2013; and
- “Manual Adjustment for 2013 Load Forecast” represents the amount to be reflected in the 2013 load forecast. This amount uses the “gross” impact, which is calculated by multiplying each year’s CDM program impact or persistence by (1 + g) from the second table. In addition, the impact of the 2013 CDM programs on 2013 “actual” consumption is divided by 2 to reflect the “half year” rule. Since the 2013 CDM programs are not in effect at midnight on January 1, 2013, the “annualized” results reported in the OPA report will overstate the “actual” impact. In the absence of information on the timing and uptake of CDM programs in their initial year, a “half-year” rule may proxy the impact.

a) Please input the “gross” and “net” cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports into, respectively, cells D26 and E26.

b) Please verify the inputs and results of the model.

c) Please provide SLHI’s views on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. What, if any, refinements to this approach should be considered.

SLHI Response

a) The "gross" and "net" cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports have been entered, respectively, into cells D26 and E26 and provided in the live spreadsheet titled "LFCDMAWF_Sioux_Lookout_Hydro_20130418_Completed".

b) The inputs and results of the model have been verified.

c) Sioux Lookout Hydro agrees with the methodology used to determine the CDM savings that will underlie the 2013 CDM amount for the LRAMVA. With regards to the manual CDM adjustment for the 2013 test year load forecast, Sioux Lookout Hydro submits it should be a value that represents the net level since this is consistent with 2013 cost of service settlement agreements to date. In addition, the 2011 value should not be included in the manual CDM adjustment. The results of the 2011 programs and how they persist into 2013 have been reflected in the actual 2011 power purchases used in the regression analysis. In Sioux Lookout Hydro's view to include the 2011 value in the manual CDM adjustment would be a double count. With regards to the 2013 value used in the manual CDM adjustment, Sioux Lookout Hydro is concerned with using the "half year rule" since it is Sioux Lookout Hydro's understanding that there should be consistent treatment on how the load forecast is adjusted and how the LRAMVA threshold is determined. Since a full year amount is used in the LRAMVA threshold calculation for 2013 then a full year for 2013 should be used in the manual CDM adjustment.

3-VECC-15

Reference: *Exhibit 3, Tab 3, Schedule 3*
Appendix 2-F

a) Please provide the actual Other Revenue for 2012 in the same format as Appendix 2-F.

SLHI Response

a) See below for Other Revenue for 2012.

Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2012						
		Actual						
	Reporting Basis	CGAAP						
4235	**Specific Service Charges**	$ 18,315						
4225	**Late Payment Charges**	$ 34,326						
4210	**Rent from Electric Property**	$ 43,262						
4080-2	SSS Revenue	$ 8,023						
4305	Regulatory Debits							
4355	Gain on Disposition of Utility and Other Property							
4360	Loss on Disposition of Utility and Other Property	-$ 234						
4375	Revenues from Non-Utility Operations	$ 45,180						
4380	Expenses of Non-Utility Operations	-$ 39,991						
4390	Miscellaneous Non -Operating Income	$ -						
4405	Interest and Dividend Income	-$ 6,045						
Specific Service Charges		$ 18,315	$ -	$ -	$ -	$ -	$ -	$ -
Late Payment Charges		$ 34,326	$ -	$ -	$ -	$ -	$ -	$ -
Other Distribution Revenues		$ 51,284	$ -	$ -	$ -	$ -	$ -	$ -
Other Income or Deductions		-$ 1,090	$ -	$ -	$ -	$ -	$ -	$ -
Total		$102,836	$ -	$ -	$ -	$ -	$ -	$ -

Account Breakdown Details

Account 4405 - Interest and Dividend Income

	2012						
Reporting Basis	**Actual**						
Miscellaneous Interest revenue	$ (1,027)						
Bank Deposit Interest	$ (6,213)						
Sundry Earnings / Interest Revenue Variance Accounts	$ (8,426)						
Smart Meter Variance Disposal Interest	$ 21,711						
Total	$ 6,045	$ -	$ -	$ -	$ -	$ -	$ -

EXHIBIT 4 – OPERATING COSTS

4-VECC-16

Reference: Exhibit 2, Appendix 2-A/Exhibit 4, Tab 1, Schedule 1, pg. 3

a) The Operation and Maintenance Expenses shown at Table 11 at page 23 of the Asset Management are significantly lower than the forecast 2012 and 2013 equivalent budgets (2012- $677,652 vs. $905,256 and $705,219 vs. $829,968). Please explain this discrepancy.

SLHI Response

a) There were certain expenses not included in the Asset Management Plan (AMP) but were included in the 2012 and 2013 amounts included in the Application.

   Table 4.2, Exhibit 4/Tab 1/Sch. 1/pg. 3 includes the Operation and Maintenance costs transferred from the Smart Meter Variance account in 2012 totalling $116,681. Also included in this Table, but not in the AMP, are on-going costs of smart meter operations and maintenance of $78,832. The balance of $32,091 is a result of adjustments made to the projected numbers after the AMP was published.

   For 2013, the discrepancy can be explained similar to 2012. On-going smart meter operations and maintenance costs were not included in the AMP, but were included in Table 4.2. See Table 4.25 – Cost Driver Table, Exhibit 4, Tab 2, Schedule 3, page 1, for more information on the amounts.

   The Asset Management Plan is intended to be a living document and will be reviewed and updated as more information is collected. The development of the Asset Management Plan was well underway before SLHI received a decision on the Smart Meter Disposal Application, and the on-going smart meter operations and maintenance costs should have been included in the final version.

4-VECC-17

Reference: Exhibit 4, Tab 1, Schedule 1, pg. 4

a) The OEB cohort of similar utilities to SLHI include: Atikokan Hydro; Chapleau Public Utilities; Espanola Regional Hydro; Fort Frances Power; Kenora Hydro and Hearst Power. Using the OEB's most recent 2011 Electricity Yearbook statistics please compile a table similar to Table 4.10 which compares SLHI's OM&A per customer to these utilities.

SLHI Response

a) See the table below:

OM&A Per Customer and FTE For 2011							
	Sioux Lookout Hydro Inc.	Atikokan Hydro	Chapleau Public Utilities	Espanola Regional Hydro	Fort Frances Power	Kenora Hydro	Hearst Power
Number of Customers	2,755	1,661	1,293	3,299	3,775	5,572	2,817
Total recoverable OM&A	$1,170,206	$937,444	$549,332	$1,075,948	$1,325,587	$2,016,125	$869,260
OM&A Cost per Custom	**$424.76**	**$564.39**	**$424.85**	**$326.14**	**$351.15**	**$361.83**	**$308.58**
Number of FTEEs	8	7	5	5	9	15	6
Customers/FTEEs	**344**	**237**	**259**	**660**	**419**	**371**	**470**
OM&A Cost per FTEE	**$146,275.75**	**$133,920.57**	**$109,866.40**	**$215,189.60**	**$147,287.44**	**$134,408.33**	**$144,876.67**

4-VECC-18

Reference: Exhibit 4, Tab 1, Schedule 1, pg. 6

a) Please explain why SLHI believes it is appropriate to collect the $84,746 in HR expenses over four years (rather than simply expensing the entire amount in 2012)?

SLHI Response

a) The amount of $84,746 was a one-time cost in 2012 and exceeds our materiality threshold of $50,000. If the amount were expensed in 2012 only, they would not be recovered through rates.

4-VECC-19

Reference: Exhibit 4, Tab 2, Schedule 3, pg. 5

a) Please provide the actual consulting costs to-date for the 2013 rate application (include outstanding invoices).

SLHI Response

a) The actual consulting costs to-date for the 2013 rate application are $7,415. SLHI was able to complete much of the application internally and therefore did not incur as much consulting fees as forecasted. There will be additional fees for assistance with interrogatories as well as intervenor costs and perhaps lawyer fees if necessary. These are very difficult to forecast with any degree of accuracy.

4-VECC-20

Reference: Exhibit 4, Tab 2, Schedule 3, pgs. 1-3

a) Please provide the breakdown and comparison of costs in account 5315 (Customer Billing for 2008 vs. 2013

SLHI Response

a) See Below for the breakdown and comparison of costs in account 5315 for 2008 vs 2013 Test.

2008 Vs 2013 Test Comparison of 5315 - Customer Billing		
	2008	**2013 Test**
Bank and Service Charges	60,765	55,183
Contracted Settlement Services	12,548	15,918
Contracted Billing Services	59,976	62,571
Wages	43,359	61,540
Total	**176,648**	**195,212**

4-VECC-23

Reference: Exhibit 4, Tab 2, Schedule 3, pg. 1

a) Please describe/show the methodology used to estimate the bad debt expense (account 5335) of $20,000.

b) What was the actual bad debt expense in 2012?

SLHI Response

a) The methodology used to estimate the bad debt expense of $20,000 is based on historical trends for the last five years. SLHI does not take into consideration any account write-off recoveries in the forecast due to the unpredictable nature of recoveries.

b) The actual bad debt expense for 2012 was $20,094.

4-VECC-25

Reference: Exhibit 4, Tab 1, Schedule 5

a) Please provide association fees paid to the EDA for each of the years 2008 through 2013 (forecast)

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

SLHI Response

a) Association fees paid to the EDA from 2008 through 2013 (forecast) are:

2008	2009	2010	2011	2012	2013
$6,700	$6,850	$7,150	$7,380	$7,800	$8,200

b) All other association memberships are:

Association Memberships 2008 to 2013 (forecast)						
	Year					
Description	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
EDA Northwest District Association Fees	667	333	0	0	0	0
EUS&A Fees	0	2,011	0	0	0	0
Utility Standard Forum	6,000	6,200	7,500	8,500	8,750	8,750
Electrical Safety Association	2,345	2,375	2,400	2,516	2,502	2,506
Ontario Energy Board Registration Fee	800	800	800	800	800	800
Ontario Energy Board Annual Assessment Fees	9,157	10,102	10,658	12,100	11,737	10,867

4-VECC-26

Reference: Exhibit 4, Tab 2

a) Does SLHI purchase property or other insurance from the MEARIE Group? If yes please provide a description of the insurance coverage and the premiums paid in each year 2008 through 2013 (forecast).

b) If yes, was this product acquired as a sole source contract or by competitive tender.

SLHI Response

a) Yes SLHI purchases Liability and Vehicle Insurance from the MEARIE Group. SLHI holds property insurance with another broker. The premiums paid from 2008 through to 2013 are as follows:

Insurance Coverage and Premiums Paid to the MEARIE Group						
	Year					
Description	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Liability Insurance Premium	9,765	7,982	6,669	5,060	7,266	7,885
Liability Premium deduction	0	0	-2,480	0	-2,371	0
Total Liability Premium paid	**9,765**	**7,982**	**4,189**	**5,060**	**4,895**	**7,885**
Vehicle Insurance Premium	**6,404**	**6,439**	**6,254**	**7,478**	**7,330**	**7,404**

b) This product was acquired as a sole source contract.

4-Staff-14

Ref: Exhibit 4/Tab 2/Sch. 7/ p. 8/Table 4.74
Ref: Revenue Requirement Work Form
Ref: Chapter 2 Appendices

The depreciation expense for the 2013 test year of $229,267 in the Chapter 2 Appendices, App.2-CH_MCGAAP_DepExp_2013, does not reconcile to the amount shown on the RRWF of $180,404.

a) Please reconcile and update the appropriate evidence in the Chapter 2 Appendices, RRWF and Table 4.74.

SLHI Response

a) See below for the updated Table 4.74 reconciled to the original RRWF.

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013 - Note Sioux Lookout Hydro will be adopting IFRS January 1, 2014

Year 2013 MCGAAP

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Note to explain variance
1611	Computer Software (Formally known as Account 1925)	$ 1,000.00	5.00	20.00%	$ 17,528.84	$ 15,607.00	$ 1,921.84	1
1612	Land Rights (Formally known as Account 1906)	$ -		0.00%	$ -	$ -	$ -	
1805	Land	$ -		0.00%	$ -	$ -	$ -	
1808	Buildings	$ -	25.00	4.00%	$ 3,631.43	$ 3,675.00	-$ 43.57	2
1810	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	
1815	Transformer Station Equipment >50 kV	$ -		0.00%	$ -	$ -	$ -	
1820	Distribution Station Equipment <50 kV	$ -		0.00%	$ -	$ -	$ -	
1825	Storage Battery Equipment	$ -		0.00%	$ -	$ -	$ -	
1830	Poles, Towers & Fixtures	$ 49,073.00	45.00	2.22%	$ 70,114.17	$ 70,114.00	$ 0.17	
1835	Overhead Conductors & Devices	$ 12,268.00	45.00	2.22%	$ 18,507.72	$ 18,508.00	-$ 0.28	
1840	Underground Conduit	$ 5,000.00	50.00	2.00%	$ 2,849.59	$ 2,850.00	-$ 0.41	
1845	Underground Conductors & Devices	$ 89,152.00	40.00	2.50%	$ 21,846.88	$ 21,847.00	-$ 0.12	
1850	Line Transformers	$ 59,767.00	40.00	2.50%	$ 37,103.72	$ 37,104.00	-$ 0.28	
1855	Services (Overhead & Underground)	$ -		0.00%	$ -	$ -	$ -	
1860	Meters	$ -	25.00	4.00%	$ 11,775.60	$ 12,035.00	-$ 259.40	3
1860	Meters (Smart Meters)	$ 1,680.00	15.00	6.67%	$ 43,221.73	$ 43,222.00	-$ 0.27	
1905	Land	$ -		0.00%	$ -	$ -	$ -	
1908	Buildings & Fixtures	$ -		0.00%	$ -	$ -	$ -	
1910	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	
1915	Office Furniture & Equipment (10 years)	$ -	10.00	10.00%	$ 1,758.25	$ 1,851.00	-$ 92.75	4
1915	Office Furniture & Equipment (5 years)	$ -		0.00%	$ -	$ -	$ -	
1920	Computer Equipment - Hardware	$ -		0.00%	$ -	$ -	$ -	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,000.00	5.00	20.00%	$ 10,299.97	$ 9,830.00	$ 469.97	5
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		0.00%	$ -	$ -	$ -	
1930	Transportation Equipment(8 years)	$ -	8.00	12.50%	$ 19,658.38	$ 19,693.00	-$ 34.62	6
1930	Transportation Equipment(5 years)	$ -	5.00	20.00%	$ 6,063.03	$ 6,237.00	-$ 173.97	7
1940	Tools, Shop & Garage Equipment	$ 5,000.00	10.00	10.00%	$ 4,513.96	$ 5,519.00	-$ 1,005.04	8
1945	Measurement & Testing Equipment	$ 7,000.00	10.00	10.00%	$ 1,403.50	$ 1,643.00	-$ 239.50	9
1950	Power Operated Equipment	$ 86,000.00	8.00	12.50%	$ 9,330.25	$ 14,662.00	-$ 5,331.75	10
1955	Communications Equipment	$ -	10.00	10.00%	$ 1,504.29	$ 1,504.00	$ 0.29	
1955	Communication Equipment (Smart Meters)	$ -		0.00%	$ -	$ -	$ -	
1960	Miscellaneous Equipment	$ -		0.00%	$ -	$ -	$ -	
1975	Load Management Controls Utility Premises	$ -		0.00%	$ -	$ -	$ -	
1980	System Supervisor Equipment	$ -		0.00%	$ -	$ -	$ -	
1985	Miscellaneous Fixed Assets	$ 2,000.00	10.00	10.00%	$ 1,317.18	$ 1,491.00	-$ 173.82	11
1995	Contributions & Grants	-$ 92,000.00	40.00	2.50%	-$ 26,948.90	-$ 31,517.00	$ 4,568.10	12
etc.		$ -		0.00%	$ -	$ -	$ -	
		$ -		0.00%	$ -	$ -	$ -	
	Total	$ 227,940.00			$ 255,479.58	$ 255,875.00	-$ 395.42	
	Depreciation Expense included in relevant expense accounts				-$ 49,258.00			
	Immaterial difference due to notes explained in Ex 4/Tab 2/Sched 7/p. 8				$ 395.42			
	Depreciation expense adjustment resulting from amortization of Account 1576 and removal of sentinel light depreciation				-$ 26,213.00			
	Total Depreciation expense to be included in the test year revenue requirement				**$ 180,404.00**			

4-Staff-15

Ref: Exhibit 4/Tab 1/Sch. 1/p. 8

SLHI has stated that a 2.2 % inflation increase has been applied to the expected expenditures except in cases where it is a known amount. Please identify the source document for the inflation assumption.

SLHI Response

The stated inflation rate should read 2% not 2.2%. SLHI verified that 2% was applied to expenses. The source of the inflation assumption is update released by the Board on March 13, 2012.

4-Staff-16

Ref: Exhibit 4/Tab 1/Sch. 1/ p. 3
Ref: Exhibit 8/Sch. 1/p. 1
Ref: Cost Allocation Model/Tab O1/Cell C57
Ref: Revenue Requirement Work Form/Tab 3/Cell E36

Board staff notes that the value for OM&A Expenses has been variously stated as $1,554,393, $1,554,419 and $1,549,433 in the application. Please confirm and identify the correct value.

SLHI Response

The correct value is $1,554,419 as stated on Exhibit 8/Sch. 1/p. 1. The value of $1,549,433 in cell E36 is correct. Cell E38 contains an amount of $4,986 for property insurance which is included in the total OM&A expenses ($1,549,433 + 4,986 = $1,554,419) in Exhibit 8. The difference of $26 of $1,554,393(from Exhibit 4/Tab 1/Sch. 1/p. 3) and $1,554,419 is due to rounding.

4-Staff-17

Ref: Exhibit 4/Tab 1/Sch. 1/p. 4

Table 4.10 shows the OM&A cost per customer as $423.99, $579.43 and $563.80 respectively for the years 2011 (historical), 2012 (bridge) and 2013 (test).

a) Please explain the circumstances driving the increase in OM&A cost per customer from 2011 to 2012.

SLHI Response

a) The main driver for the increase from 2011 to 2012 is the inclusion of smart meter OM&A costs. SLHI completed the smart meter implementation in 2011 and applied for final disposition of variance accounts 1555 and 1556, which was approved by the Board in August 2012. The amount of OM&A expenses transferred from Account 1556 was $116,682. Additionally the OM&A expenses for 2012 included smart meter operations previously included in the variance account amounting to approximately $78,832.

   Another circumstance driving the increase was succession planning due to the retirement of the President/CEO in 2012 (see Exhibit 4/Tab 2/Sch. 4/p. 5). During the transition there was an overlap of wages between the outgoing and incoming President/CEO of approximately $36,144. As a result of the retirement and succession planning the company underwent some reorganization which resulted in an increase of approximately $73,279, which is mainly due to the hiring of an additional Apprentice Lineman.

Finally, forecasted regulatory expenses related to the Cost of Service Application and the new capitalization policy account for approximately $81,370 of the increase to OM&A for 2012.

4-Staff-18

Ref: Exhibit 4/Tab 1/Sch. 1/p. 1

a) Please identify the increases (decreases) in OM&A expense for the test year, arising from a source other than a decrease (increase) in capitalized overhead.

SLHI Response

a) In the test year the total OM&A costs will decrease compared to 2012. This is mainly due to the one-time adjustment to dispose of Account 1556 in 2012 offset by ongoing expenses due to smart meter operations. Another reason would be the decrease in costs due to the retirement of the President/CEO explained in interrogatory 4-Staff-17.

4-Staff-19

Ref: Exhibit 4/Tab 2/Sch. 4/p.3

Table 4.40 shows the number of employees as 8, 8.37 and 9 respectively for the years 2011 (historical), 2012 (bridge) and 2013 (test). Total salary and wages for the same years is shown as $612,696, $703,255 and $641,205 respectively.

a) From 2011 to 2012, please explain the circumstances driving the 14.8% increase in total salary and wages given that the increase in the number of FTEs is only 4.6% for the same period.

b) From 2012 to 2013, please explain the circumstances driving the 8.8% decrease in total salary and wages given that the number of FTEs increases by 7.5% for the same period.

SLHI Response

a) The increase from 2011 to 2012 is explained by the severance and retirement allowance paid out to two employees, as well as the addition of an extra employee in July 2012.

b) The decrease from 2012 to 2013 is explained due to the absence of the retirement and severance explained in a).

4-Staff-20

Ref: Exhibit 4/Tab 2/ Sch. 4/p. 6-7

OMERS has announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013. SLHI states that this increase in OMERS pension costs has been included in the cost of current benefits in this application.

a) Please provide the forecasted increase in OMERS pension costs by years and the documentation to support the increases.

SLHI Response

a) SLHI has included the OMERS pension costs in Table 4.41, Exhibit 4/Tab 2/Sch. 4/p. 7. The premiums decreased from $58,624 in 2012 to $56,507 in 2013 due to the transition period where SLHI employed both the incoming and outgoing President/CEO along with the addition of the Apprentice.

4-Staff-21

Ref: Exhibit 4/Tab 2/Sch. 4/p. 8

SLHI has provided post-retirement benefit costs separately from current benefit costs.

a) Please provide the most recent actuary report(s).

SLHI Response

a) The post-retirement benefits costs include a minimal amount paid for retiree life insurance of which there are three individuals. The balance is for an agreement made between an out-going senior executive and SLHI to continue providing Health, Dental and Vision Care benefits until the age of 65. An actuary report was deemed by SLHI's external auditor to be unnecessary given there was only one employee entitled to this benefit. The benefit is payable for the next four years only, at which time the individual turns 65. Since an actuary report can cost anywhere from $2,000 to $5,000, it is more prudent to simply adjust the liability each year based on forecasted benefit premiums for the year.

4-VECC-27

Reference: Exhibit 4, Tab 2, Schedule 4, pg. 1

a) Please provide an update as to the negotiation of the Power Work Union contract. If a final agreement has been reached please provide the annual wage increase agreed to.

SLHI Response

a) The negotiations with the Power Worker's Union are scheduled to take place the third week of May.

4-VECC-28

Reference: Exhibit 4, Tab 2, Schedule 3 & 4

a) Please confirm that one full time apprentice lineman is being employed for succession planning.

b) When does SLHI expect the position for which this apprentice was hired to become vacant (the incumbent retire)?

SLHI Response

a) SLHI confirms that one full time apprentice lineman is being employed for succession planning.

b) SLHI expects the position for which this apprentice was hired to become vacant within the next 4 to 5 years.

4-VECC-29

Reference: Exhibit 4, Tab 2, Schedule 4, pg. 5

a) The evidence states the former meter reader was retained after the work for this job was eliminated due to smart meters. The new position was classified as a Groundsman. Please explain what this position is responsible for and who did this work prior to this change.

SLHI Response

a) This job classification is still being developed. The employee is a member of the Power Worker's Union, and during the last collective agreement negotiation in 2010 a letter of understanding was signed by both parties to explore additional duties within the company in order to provide continuous employment for the Meter Reader. It should be noted that not all classifications in the collective agreement are associated with existing employees of SLHI.

   The Groundsman classification was chosen as the most suitable class within the current collective agreement given the new and existing duties assigned to the individual. The individual did perform some of the same duties prior to the reclassification such as performing Groundsman duties when required by the line crew, and also some general labourer duties. Additional duties that have been assigned are related to maintaining and updating SLHI's assets in the Asset Management Software as well as assisting with the development of the mapping in the mapping system software. The individual was also given the responsibility of maintaining and tracking inventory.

4-Staff-22

Ref: Exhibit 4/Tab 3/Sch. 2
Ref: Income Tax/ PILs Workform

Table 4.3-5 – 2012 CCA /UCC Continuity Schedule (CGAAP) in Exhibit 4, Tab 3, Schedule 2 does not match the 2012 Bridge Year Schedule 8 in the Income Tax / PILs Workform.

a) Please update Table 4.3-5 in SLHI’s evidence to match the 2012 Bridge Year Schedule 8 in the Workform.

SLHI Response

a) The Table 4.3-5 in SLHI’s evidence does not match the 2012 Bridge Year Schedule 8 in the Workform because it is based on CGAAP not MCGAAP. Exhibit 4/Tab 3/ Sch. 3/p. 1 Table 4.44 matches Schedule 8 for the Bridge year in the PILs Workform. Table 4.3-5 – 2012 CCA/UCC Continuity Schedule (CGAAP) should be replaced with the following table:

Table 4.3-5(a) – 2012 CCA/UCC Continuity Schedule (MCGAAP)

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 3,880,847			$ 3,880,847	$ -	$ 3,880,847	4%	$ 155,234	$ 3,725,613
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 33,544	$ 29,650	-$ 1,295	$ 61,899	$ 14,178	$ 47,722	20%	$ 9,544	$ 52,355
10	Computer Hardware/ Vehicles	$ 60,684	$ 118,093	-$ 1,753	$ 177,024	$ 58,170	$ 118,854	30%	$ 35,656	$ 141,368
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 11,250	$ 52,240		$ 63,490	$ 26,120	$ 37,370	100%	$ 37,370	$ 26,120
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 81			$ 81	$ -	$ 81	45%	$ 36	$ 45
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 1,779,493	$ 768,849	-$ 294,462	$ 2,253,880	$ 237,194	$ 2,016,687	8%	$ 161,335	$ 2,092,545
50	Data Network Infrastructure Equipment - post Mar 2007	$ 5,021			$ 5,021	$ -	$ 5,021	55%	$ 2,762	$ 2,259
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 5,770,920	$ 968,832	-$ 297,510	$ 6,442,242	$ 335,661	$ 6,106,581		$ 401,937	$ 6,040,305

EXHIBIT 5 – COST OF CAPITAL AND RATE OF RETURN

5-Staff-23

Ref: Exhibit 5/Tab 1/Sch. 1/p. 1-2

With respect to the return on equity, SLHI states:

> *"SLHI is requesting a return on equity ("ROE") for the 2013 Test year of 9.12% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. SLHI understands that the OEB will be finalizing the ROE for 2013 rates based on January 2013 market interest rate information. SLHI's use of an ROE of 9.12% is without prejudice to any revised ROE that may be adopted by the OEB in early 2013."*

A similar statement is made with respect to the deemed short-term debt rate.

On February 14, 2013, the Board issued a letter to all distributors documenting the updated Cost of Capital parameters for 2013 Cost of Service applications with rates effective May 1, 2013.

The updated Cost of Capital parameters are summarized in the following table:

Parameter	**Updated values for Cost of Service rates effective May 1, 2013**
Return on Equity	8.98%
Deemed Long-term debt rate	4.12%
Deemed Short-term debt rate	2.07%

a) Please update the necessary tables in Exhibit 5, including Appendix 2-OA, for the 2013 test year, reflecting the updated Cost of Capital parameters as documented above and as applicable to SLHI's application.

5-VECC-30

Reference: Exhibit 5, Tab 1, Schedule 2

a) Please update Table 5.1 (and RRWF) for the Board's cost of capital update of February 14, 2013 (see also Board Staff IR #23).

SLHI Response

SLHI updated the RRWF and Appendix 2-OA for the 2013 test year reflecting the updated Cost of Capital parameters. The updated Exhibit 5, Table 5.1 for 2013 is show below using the updated rate base determined from the adjustment to the cost of power from IR 2-Staff-9 and the actual 2012 capital expenditures from IR 2-VECC-3 and 2-VECC-4.

Table 5.1 – Deemed Capital Structure 2008 to 2013

Deemed Capital Structure for 2008- Board Approved

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,062,641	49.30%	6.10%	186,821
Unfunded Short Term Debt	248,490	4.00%	4.47%	11,108
Total Debt	3,311,131	53.30%		197,929
Common Share Equity	2,901,123	46.70%	8.57%	248,626
Total equity	2,901,123	46.70%		248,626
Total Rate Base	6,212,254	100.00%	7.19%	446,555

Deemed Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	2,771,464	49.30%	4.73%	131,090
Unfunded Short Term Debt	224,865	4.00%	4.47%	10,051
Total Debt	2,996,329	53.30%		141,142
Common Share Equity	2,625,302	46.70%	8.57%	224,988
Total equity	2,625,302	46.70%		224,988
Total Rate Base	5,621,631	100.00%	6.51%	366,130

Deemed Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	2,789,176	52.70%	2.93%	81,731
Unfunded Short Term Debt	211,702	4.00%	4.47%	9,463
Total Debt	3,000,878	56.70%		91,194
Common Share Equity	2,291,676	43.30%	8.57%	196,397
Total equity	2,291,676	43.30%		196,397
Total Rate Base	5,292,553	100.00%	5.43%	287,590

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,080,525	56.00%	3.10%	95,634
Unfunded Short Term Debt	220,038	4.00%	4.47%	9,836
Total Debt	3,300,563	60.00%		105,469
Common Share Equity	2,200,375	40.00%	8.57%	188,572
Total equity	2,200,375	40.00%		188,572
Total Rate Base	5,500,938	100.00%	5.35%	294,042

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,131,262	56.00%	3.42%	107,050
Unfunded Short Term Debt	223,662	4.00%	4.47%	9,998
Total Debt	3,354,924	60.00%		117,047
Common Share Equity	2,236,616	40.00%	8.57%	191,678
Total equity	2,236,616	40.00%		191,678
Total Rate Base	5,591,539	100.00%	5.52%	308,725

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,302,366	56.00%	3.43%	113,272
Unfunded Short Term Debt	235,883	4.00%	2.07%	4,883
Total Debt	3,538,250	60.00%		118,155
Common Share Equity	2,358,833	40.00%	8.57%	202,152
Total equity	2,358,833	40.00%		202,152
Total Rate Base	5,897,083	100.00%	5.43%	320,307

Deemed Capital Structure for 2013

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,442,492	56.00%	4.12%	141,831
Unfunded Short Term Debt	245,892	4.00%	2.07%	5,090
Total Debt	3,688,384	60.00%		146,921
Common Share Equity	2,458,923	40.00%	8.98%	220,811
Total equity	2,458,923	40.00%		220,811
Total Rate Base	6,147,307	100.00%	5.98%	367,732

5-VECC-31

Reference: Exhibit 5, Tab 1

a) Please provide the actual and deemed rates of return on equity and capital for each of the years 2009 through 2012.

SLHI Response

a) See below for a table providing the actual and deemed rates of return on equity:

Actual and Deemed Rates of Return on Equity				
	Year			
Description	**2009**	**2010**	**2011**	**2012**
Actual ROE	3.16%	13.65%	9.67%	9.22%
Deemed ROE	8.57%	8.57%	8.57%	8.57%

It should be noted that the low Return on Equity in 2009 is due to the impairment and subsequent write-off of SLHI's Goodwill of $300,979. SLHI submitted a letter to our external auditor citing several factors that supported the decision to remove goodwill from the books. Our auditor accepted the letter as evidence that there was indeed no goodwill in the company. See below for an excerpt of the letter:

"The following issues provide reasonable justification for the impairment:

- *During March of 2008 Hydro One submitted an expression of interest to purchase Sioux Lookout Hydro for an amount equal to the net book value at the end of 2008 plus a premium of $100,000. At this time Sioux Lookout Hydro had projected future growth and the McKenzie Forest Products mill was in full operation.*

- *Sioux Lookout Hydro's largest customer, McKenzie Forest Products, closed its operations in 2008. As a result, our load decreased by approximately 35 MW per year, and MWHs sold decreased by approximately 21,800 MWHs per year. Looking forward, if McKenzie Forest Products were to start production again it would be on an intermittent basis.*

- *There has been no growth in the utility in the last four years. Our customer base has remained constant at just under 2,750 customers, and there is not expected to be any significant growth in the future.*

- *Due to increased regulatory burden imposed by the Ontario Energy Board (OEB), and the Smart Meter initiative, an additional staff member will be required to balance workloads, while at the same time no additional revenue will be generated.*

- *Recently, the Electrical Safety Authority revoked Sioux Lookout Hydro's contractor's License due to an OEB regulation. The impact is that Sioux Lookout Hydro is no longer allowed to contract work out. This further reduces the utility's ability to generate revenue.*

With the implementation of IFRS, Sioux Lookout Hydro will be required to undergo a valuation of the company which will be an unnecessary cost to the company since it is apparent from the issues listed above that no Goodwill exists in the company."

EXHIBIT 7 – COST ALLOCATION

7-VECC-32

Reference: Exhibit 7, Schedule 1, page 2

a) Please confirm that for classes other than Residential, GS<50 and GS>50 the customers are required to own and maintain the service assets.

b) If this is not the case, please explain why there are not Services weighting factors for these classes.

SLHI Response

a) SLHI confirms that for classes other the Residential, GS<50 and GS>50 the customers are required to own and maintain the service assets.

b) N/A

7-VECC-33

Reference: Exhibit 7, Schedule 2, page 3

a) The Application states that the revenue to cost ratio for Street Lighting is being reduced to 75% (from 83%) to reduce rate impacts. However, the Bill Impacts provided in Appendix 2-W indicate that the bill impact for Street Lighting is roughly 2.5% - less than the 6.5% impact for Residential. Please explain more fully, why the Street Lighting ratio needs to be decreased in order to address bill impacts.

SLHI Response

a) SLHI based this decision on past adjustments to the Street Lighting class which came about in the 2008 Cost of Service Application. The total percent increase to the street light class from 2008 to 2012 is 76.92% mainly due to bringing this class to the lower of the OEB range of 70% - 120%. SLHI feels that minimizing impact for this one class is appropriate given the large increases in the past five years. The table below illustrates the bill impact from the July 1, 2008 approved rates to the September 1, 2012 approved rates.

Bill Impacts

Customer Class: **Street Lighting**

Consumption	120	kW	May 1 - October 31 / November 1 - April 30 (Select this radio button for applications filed after
	40000	kWh	
	531	Connections	

	Charge Unit	July 1, 2008 Approved Rates Rate ($)	Volume	Charge ($)	September 1, 2012 Approved Rates Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 3.2100	531	$ 1,704.51	$ 9.8700	531	$ 5,240.97	$ 3,536.46	207.48%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 9.3139	120	$ 1,117.67	$ 26.0218	120	$ 3,122.62	$ 2,004.95	179.39%
Smart Meter Disposition Rider			120	$ -		120	$ -	$ -	
LRAM & SSM Rate Rider			120	$ -		120	$ -	$ -	
Low Voltage Rate Adder	per kW		120	$ -	$ 0.8534	120	$ 102.41	$ 102.41	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
Sub-Total A				$ 2,822.18			$ 8,465.99	**$ 5,643.82**	**199.98%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.3647	120	$ 43.76	-$ 2.1406	120	-$ 256.87	-$ 300.64	-686.95%
Global Adjustment Rate Rider			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
Low Voltage Service Charge			120	$ -		120	$ -	$ -	
Smart Meter Entity Charge						120	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,865.94**			**$ 8,209.12**	**$ 5,343.18**	**186.44%**
RTSR - Network	per kW	$ 1.1745	120	$ 140.94	$ 1.5114	120	$ 181.37	$ 40.43	28.68%
RTSR - Line and Transformation Connection	per kW	$ 0.4355	120	$ 52.26	$ 0.3542	120	$ 42.50	-$ 9.76	-18.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,059.14**			**$ 8,432.99**	**$ 5,373.85**	**175.67%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	42568	$ 221.35	$ 0.0052	42568	$ 221.35	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	42568	$ 46.82	$ 0.0011	42568	$ 46.82	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	40000	$ 280.00	$ 0.0070	40000	$ 280.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0870	41568	$ 3,616.42	$ 0.0870	41568	$ 3,616.42	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0630	27244	$ 1,716.34	$ 0.0630	27244	$ 1,716.34	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0990	7662	$ 758.56	$ 0.0990	7662	$ 758.56	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1180	7662	$ 904.14	$ 0.1180	7662	$ 904.14	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 7,297.99**			**$ 12,671.84**	**$ 5,373.85**	**73.63%**
HST		13%		$ 948.74	13%		$ 1,647.34	$ 698.60	73.63%
Total Bill (including HST)				$ 8,246.72			$ 14,319.18	$ 6,072.45	73.63%
Ontario Clean Energy Benefit [1]				-$ 824.67			-$ 1,431.92	-$ 607.25	73.64%
Total Bill on RPP (including OCEB)				**$ 7,422.05**			**$ 12,887.26**	**$ 5,465.20**	**73.63%**
Total Bill on TOU (before Taxes)				**$ 6,986.62**			**$ 12,360.47**	**$ 5,373.85**	**76.92%**
HST		13%		$ 908.26	13%		$ 1,606.86	$ 698.60	76.92%
Total Bill (including HST)				$ 7,894.88			$ 13,967.33	$ 6,072.45	76.92%
Ontario Clean Energy Benefit [1]				-$ 789.49			-$ 1,396.73	-$ 607.24	76.92%
Total Bill on TOU (including OCEB)				**$ 7,105.39**			**$ 12,570.60**	**$ 5,465.21**	**76.92%**

Loss Factor (%)	6.42%		6.42%

7-Staff-24

Ref: Exhibit 7/Tab 2/p. 3

Board staff notes that SLHI is proposing to make adjustments to the revenue-to-cost ratios derived from the 2013 updated cost allocation study as indicated in the table below.

	Revenue-to-Cost Ratios	
Class	2013 Updated Cost Allocation study	2013 Proposed Rates
Residential	90.31%	96.36%
GS < 50	115.16%	109.87%
GS 50 to 4,999	138.60%	119.85%
Street Lighting	83.00%	74.91%
USL	81.01%	80.93%

If the ratios for the Street Lighting and USL classes were to remain unadjusted at respectively 83% and 81.01%, please provide:

a) The bill impact for these two classes;
b) The ratio for the Residential class, while keeping the ratios for the GS<50 and GS 50 to 4,999 as proposed, i.e. 109.87% and 119.85%, respectively; and
c) The ratio for the GS 50 to 4,999 class, while keeping the ratios for the Residential and GS<50 classes as proposed, i.e. 96.36% and 109.87% respectively.

SLHI Response

a) See below for the bill impact to the Street Lighting and USL classes if the revenue to cost ratios were to remain unadjusted at 83% and 81.01% respectively:

Customer Class: **Streetlighting**

Consumption 40,000 kWh 118 kW 518 **Connections**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	monthly	$ 9.8700	518	$ 5,112.66	$ 10.8113	518	$ 5,600.25	$ 487.59	9.54%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 26.0218	118	$ 3,070.57	$ 28.5034	118	$ 3,363.40	$ 292.83	9.54%
Low Voltage Rate Adder	per kW	$ 0.8534	118	$ 100.70	$ 0.9966	118	$ 117.60	$ 16.90	16.78%
Volumetric Rate Adder(s)			118	$ -		118	$ -	$ -	
Volumetric Rate Rider(s)			118	$ -		118	$ -	$ -	
Smart Meter Disposition Rider			118	$ -		118	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	118	$ -	$ -	118	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 2.1406	118	-$ 252.59	$ 1.5062	118	$ 177.73	$ 430.32	-170.36%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 8,031.34**			**$ 9,258.99**	**$ 1,227.64**	**15.29%**
RTSR - Network	per kW	$ 1.5114	118	$ 178.35	$ 1.7868	118	$ 210.84	$ 32.50	18.22%
RTSR - Line and Transformation Connection	per kW	$ 0.3542	118	$ 41.80	$ 0.3992	118	$ 47.11	$ 5.31	12.70%
Sub-Total B - Delivery (including Sub-Total A)				**$ 8,251.48**			**$ 9,516.93**	**$ 1,265.45**	**15.34%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	42568	$ 221.35	$ 0.0052	43588	$ 226.66	$ 5.30	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	42568	$ 46.82	$ 0.0011	43588	$ 47.95	$ 1.12	2.40%
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	40000	$ 280.00	$ 0.0070	40000	$ 280.00	$ -	0.00%
Energy	per kWh	$ 0.0740	42568	$ 3,150.03	$ 0.0740	43588	$ 3,225.51	$ 75.48	2.40%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 11,949.94**			**$ 13,297.30**	**$ 1,347.36**	**11.27%**
HST		13%		$ 1,553.49	13%		$ 1,728.65	$ 175.16	11.27%
Total Bill (including Sub-total B)				**$ 13,503.44**			**$ 15,025.95**	**$ 1,522.51**	**11.27%**
Loss Factor (%)		6.4200%			8.97%				

Customer Class:	Unmetered & Scattered								
	Consumption	498	kWh			1		Connections	
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	monthly	$ 21.5000	1	$ 21.50	$ 23.5602	1	$ 23.56	$ 2.06	9.58%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0083	498	$ 4.13	$ 0.0091	498	$ 4.53	$ 0.40	9.64%
Low Voltage Rate Adder	per kWh	$ 0.0027	498	$ 1.34	$ 0.0031	498	$ 1.54	$ 0.20	14.81%
Volumetric Rate Adder(s)			498	$ -		498	$ -	$ -	
Volumetric Rate Rider(s)			498	$ -		498	$ -	$ -	
Smart Meter Disposition Rider			498	$ -		498	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	498	$ -	$ -	498	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0081	498	-$ 4.03	-$ 0.0019	498	-$ 0.95	$ 3.09	-76.54%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 22.94**			**$ 28.69**	**$ 5.75**	**25.04%**
RTSR - Network	per kWh	$ 0.0050	529.972	$ 2.65	$ 0.0059	542.671	$ 3.20	$ 0.55	20.83%
RTSR - Line and Transformation Connection	per kWh	$ 0.0011	529.972	$ 0.58	$ 0.0012	542.671	$ 0.65	$ 0.07	11.70%
Sub-Total B - Delivery (including Sub-Total A)				**$ 26.18**			**$ 32.54**	**$ 6.37**	**24.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	529.972	$ 2.76	$ 0.0052	542.671	$ 2.82	$ 0.07	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	529.972	$ 0.58	$ 0.0011	542.671	$ 0.60	$ 0.01	2.40%
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	498	$ 3.49	$ 0.0070	498	$ 3.49	$ -	0.00%
Energy	per kWh	$ 0.0740	529.972	$ 39.22	$ 0.0740	542.671	$ 40.16	$ 0.94	2.40%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 72.47**			**$ 79.86**	**$ 7.39**	**10.19%**
HST		13%		$ 9.42	13%		$ 10.38	$ 0.96	10.19%
Total Bill (including Sub-total B)				**$ 81.89**			**$ 90.24**	**$ 8.35**	**10.20%**
Loss Factor (%)		6.4200%			8.97%				

b) The ratio for the Residential class, while keeping the ratios for the GS , 50 and GS 50 to 4,999 as proposed is 95.47% as illustrated in the table below:

Revenue-to-Cost Ratios - Reference: 7-Staff-24 (b)		
Rate Class	**Revenue to Cost Ratio**	**Proposed Base Revenue**
Residential	95.47%	1,210,593
GS < 50 kW	109.87%	309,095
GS 50 to 4,999 kW	119.85%	330,062
Street Lighting	83.00%	112,015
Unmetered Scattered Load	81.01%	675
Total		**1,962,440**
		1,962,405
		36

c) The ratio for the GS 50 to 4,999 class, while keeping the ratios for the Residential and GS<50 classes as proposed is 115.66% as illustrated in the table below:

Revenue-to-Cost Ratios - Reference: 7-Staff-24 (c)		
Rate Class	**Revenue to Cost Ratio**	**Proposed Base Revenue**
Residential	96.36%	1,222,660
GS < 50 kW	109.87%	309,095
GS 50 to 4,999 kW	115.66%	317,961
Street Lighting	83.00%	112,015
Unmetered Scattered Load	81.01%	675
Total		**1,962,406**
		1,962,405
		1

7-VECC-34

Reference: Exhibit 7, Schedule 2, page 3

a) Please calculate the common revenue to cost ratio for Street Lighting and USL that will maintain the proposed revenue requirement assuming that:
- The Residential ratio is maintained at 90.31%
- GS<50 is maintained at 115.16%, and
- GS 50-4999 is reduced to 120%.

SLHI Response

a) The common revenue to cost ratio for Street Lighting and USL that will maintain the proposed revenue requirement assuming that the Residential ratio is maintained at 90.31%, the GS < 50 is maintained at 115.16% and the GS 50 to 4,999 class is reduced to 120% is illustrated below:

Revenue-to-Cost Ratios - Reference: 7-VECC-34		
Rate Class	**Revenue to Cost Ratio**	**Proposed Base Revenue**
Residential	90.30%	1,140,500
GS < 50 kW	115.20%	324,985
GS 50 to 4,999 kW	120.00%	330,495
Street Lighting	119.12%	165,407
Unmetered Scattered Load	118.12%	1,011
Total		**1,962,398**
		1,962,405
		-7

EXHIBIT 8 – RATE DESIGN

8-VECC-35

Reference: Exhibit 8, Schedule 1, pages 2-4

a) Please recalculate the fixed-variable split for GS 50-4999 with the variable revenues reduced by the transformer ownership discount.

b) Using the results from part (a), please calculate the resulting monthly and variable charges for GS 50-4999 prior to any adjustment for the transformer allowance.

SLHI Response

a) SLHI confirms that the variable revenues were reduced by the transformer ownership discount when originally calculating the fixed-variable split for GS 50-4,999 as stated on line 6, page 2 of Exhibit 8 , Schedule 1, therefore no recalculation is required.

b) N/A

8-VECC-36

Reference: Exhibit 8, Schedule 1, page 6

a) What were the actual HVDS billing kW for 2011 and 2012?

b) What were the actual purchased power values for 2011 and 2012?

c) What is the 2013 forecast purchased power?

SLHI Response

a) The actual HVDS billing kW for 2011 was 146,135 kW and 147,618 kW in 2012.

b) The actual purchased power for 2011 was 76,399,313 kWh and for 2012 was 75,601,634 kWh.

c) The 2013 forecast purchased power is based on the load forecast model found in the excel worksheet entitled, Sioux Lookout 2013 Forecast_20121210, Tab “Purchased Power Model”. SLHI confirms that the 73,270,262 kWh used to calculate the cost of power does include the adjustment for CDM.

8-Staff-25

Ref: Exhibit 8/Sch. 1/ p. 12
Ref: Exhibit 8/Appendix 8-A/p. 8
Ref: 2008 Cost-of-Service Application/EB-2007-0785, Exhibit 4/Tab 2/Sch. 9/ p.1

SLHI has stated "The steps taken in the past five years have resulted in an average decrease of 1.03% in line losses from the previous Cost of Service application".

Board staff notes that SLHI's proposed Total Loss Factor ("TLF") of 1.0897 (8.97%) includes a Distribution Loss Factor ("DLF") of 1.0539 (5.39%). Board staff further notes that in SLHI's 2008 cost-of-service rate application, SLHI's approved TLF of 1.0642 (6.42%) included a DLF of 1.0594(5.94%).

a) Given that SLHI's proposed loss factor reflects distribution losses of 5.39% within SLHI's distribution system compared to distribution losses amounting to 5.94% as reflected in the previous approved loss factor, please explain the derivation of the 1.03% decrease in line losses.

SLHI Response

a) The loss factor of 6.42% from the 2008 Cost of Service application was derived from the 5 year distribution loss (DLF) average from 2002 to 2006, not the total loss factor (TLF). The table titled "Determination of Loss Adjustment Factor" from EB-2007-0785, Exhibit 4/Tab 2/Schedule 9/page 1 illustrates the calculation. SLHI is unsure why the DLF indicated in the 2008 Table found in the same Exhibit shows the DLF as 5.94%, possibly to mitigate the impact on rates. From EB-2007-0785, if you add the SLF to the DLF in the table the TLF equals 1.0639 not 1.0642. Therefore using the difference between the five year average distribution line loss(from the table "Determination of Loss Adjustment Factor") in 2006 compared to the average five year distribution line loss in 2011 is 5.39% less 6.42% which equals (1.03)%.

8-Staff-26

Ref: Exhibit 8/Appendix 8-A

With respect to SLHI's current Tariff of Rates and Charges, the 3rd paragraph in the "Application" section of the tariff sheet for each rate class reads as follows:

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

Based on recent Tariff of Rates and Charges approved by the Board in 2013 rate applications, the above paragraph should be amended as follows:

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

a) Please confirm whether SLHI has any concerns with the noted change to be applied to those classes for which the regulatory component applies, and if so why.

SLHI Response

a) SLHI confirms that they have no concerns with the noted change to be applied to those classes for which the regulatory component applies.

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

9-Staff-27

Ref: Exhibit 9/Tab 3/Sch. 1

In Guideline G-2011-0001: Smart Meter Funding and Cost Recover – Final Disposition ("Guideline G-2011-0001"), issued December 15, 2011, the Board states its expectation that proposals for the SMRR would reflect an allocation of the stranded meter costs reflecting the net book value of the conventional meters stranded by replacement by smart meters. In Section 3.7, page 23 of Guideline G-2011-0001, the Board states:

> *"The distributor should determine and support its proposed allocation, based on the principles of cost causality and practicality. The stranded meter NBV should be recovered through rate riders for applicable customer classes. A distributor must outline the manner in which it intends to allocate the stranded meter costs to the applicable customer rate classes and the rationale for the selected approach. If a distributor has recorded the NBV of the stranded meters by customer class, it should propose class-specific rate riders for each applicable class (Residential, GS < 50 kW and any other classes approved by the Board for smart meter deployment). If the NBV is not known on a class-specified basis, a distributor should propose an allocation between the affected metered customer classes and support its proposal."*

SLHI is proposing separate rate riders to recover the NBV of stranded meters from Residential and GS < 50 kW customers:

- Residential: $2.83/month for a period of two years; and
- GS < 50 kW: $2.63/month for a period of two years.

SLHI states that the allocation is based on the actual number of installed smart meters.

Board staff observes that this is equivalent to an unweighted allocation, whereby no differences in the capital costs of meters installed in each class is taken into account. In particular, the higher prices of polyphase meters, which are more prevalent for GS customer classes, are not taken into account.

a) Please explain the rationale for SLHI's proposed allocation.

b) Please provide a copy of Sheet I7.1 from SLHI's Cost Allocation Study from its previous 2009*(note should read 2008)* Cost of Service application.

c) Please confirm that the actual NBV of stranded meters as of December 31, 2012 is $181,592, reflecting accumulated depreciation up to that date.

d) Based on the information provided in b) and c), please provide class-specific SMRRs for the Residential and Gs < 50 kW. Please adequately document the methodology for allocating costs between the classes. Where available, spreadsheets for documenting the data and calculations should be provided in working Microsoft Excel format.

SLHI Response

a) SLHI has proposed to allocate stranded meter costs based on the percentages calculated by the total number of conventional meters disposed of by each respective rate class. This resulted in an allocation of costs of 87% residential and 13% GS < 50 kW. The actual NBV of stranded meter costs by class are $156,169 for the residential portion and $25,423 for the GS < 50 kW. If SLHI were to allocate the costs based on actual NBV per class the percentage of costs allocated to each class would be 86% and 14% respectively, which is a 1% difference from the proposed method. SLHI does not have many polyphase meters installed for GS < 50 kW customers, therefore the total costs to install a GS < 50 kW smart meter is only slightly higher on average. The weighted average cost per meter from SLHI's application EB-2012-0245 were $136.69 for residential and $154.51 for GS < 50. Using weighted average costs, the allocation would be 84% and 16% respectively.

b) See below for a copy of Sheet 17.1 from SLHI's Cost Allocation Study from its previous 2008 Cost of Service Application:

2006 COST ALLOCATION INFORMATION FILING
SIOUX LOOKOUT HYDRO INC.
EB-2005-0415 EB-2007-0003
May 15, 2007
Ontario
Sheet I7.1 Meter Capital Worksheet - Second Run

Click Here For Instructions on How to Complete This Worksheet

		Residential			GS <50			GS>50-Regular			Street Light			Unmetered Scattered Load			TOTAL		
		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
	Allocation Percentage Weighted Factor			74.19%			14%			12%			0%			0%			100%
	Cost Relative to Residential Average Cost			1.00			1.08			9.06			-			-			1.13
	Total	2281	196950	86.3437089	400	37200	93	40	31300	782.5	0	0	-	0	0	-	2721	265450	97.55604557
Meter Types	Cost per Meter (Installed)																		
Single Phase 200 Amp - Urban	50	1,462	73100		248	12400			0			0			0		1,710	85500	
Single Phase 200 Amp - Rural	150	809	121350		132	19800			0			0			0		941	141150	
Central Meter	250	10	2500		20	5000			0			0			0		30	7500	
Network Meter (Costs to be updated)	225		0			0			0			0			0		0	0	
Three-phase - No demand	210		0			0			0			0			0		0	0	
Smart Meters	300		0			0			0			0			0		0	0	
Demand without IT (usually three-phase)	500		0			0		38	19000			0			0		38	19000	
Demand with IT	2,100		0			0			0			0			0		0	0	
Demand with IT and Interval Capability - Secondary	2,300		0			0		1	2300			0			0		1	2300	
Demand with IT and Interval Capability - Primary	10,000		0			0		1	10000			0			0		1	10000	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0			0			0		0	0	
LDC Specific 1			0			0			0			0			0		0	0	
LDC Specific 2			0			0			0			0			0		0	0	
LDC Specific 3			0			0			0			0			0		0	0	

c) SLHI confirms that $181,592 is the NBV of stranded meter assets as of December 31, 2012, reflecting accumulated depreciation up to that date.

d) If SLHI were to allocate the stranded meter assets based on a weighted average cost for installed meters using the same methodology as the Smart Meter Cost Recovery Application, EB-2012-0245, referencing SLHI's Reply Submission page 3, the SMRRs would be $2.74 per month for Residential and $3.24 per month for GS < 50 kW as illustrated in the table below:

Net Book Value of Stranded Assets as at December 31, 2012	$181,592		
Residential	$152,537	84%	
GS < 50 kW	$29,055	16%	
	$181,592	100%	
	2013 Forecasted customers	**SMRR $**	**SMRR**
Residential	2323	$152,537	2.74
GS < 50 kW	374	$29,055	3.24
	2697		24 months

9-VECC-37

Reference: Exhibit 9, Tab 3, Schedule 1/Board Staff IR 27

a) As noted in Board Staff interrogatory 27, the Board requires a cost causality methodology for disposition of stranded meter costs. Three allocation methods have been used by other utilities: (1) actual class specific meter; (2) use of the last approved cost allocation study; (3) class specific smart meter costs as a proxy for stranded meter class specific costs.

b) Please comment on which methodology SLHI believes would be most appropriate.

c) Please provide a stranded meter rider using the installed class specific cost of smart meters as a proxy for class specific stranded meter costs.

SLHI Response

a) and b) SLHI feels that the most appropriate methodology would be to use the class specific smart meter costs as a proxy for stranded meter class specific costs. See response to the above interrogatory 9-Staff-27.

c)See response to interrogatory 9-Staff-27 (d).

9-Staff-28

Ref: Exhibit 9/Tab 2/Sch. 1/p. 5

a) Please confirm whether or not SLHI has followed article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. In other words, please confirm that the higher of, the relevant revenues (i.e. account 4082, Retail Services Revenue and /or account 4084, STR Revenue) and the incremental expenses in the associated expense accounts. (i.e. account 5315, Customer Billing, and possible 5305, Supervision and 5340, Miscellaneous Customer Accounts Expenses) is reduced (i.e. revenues debited or expenses credited) at the end of each period, with an offsetting entry to the variance account.

b) Please explain if SLHI has not followed Article 490, and if so, please quantify the variance.

c) Please confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.

SLHI Response

a) Upon reviewing the process for recording Retail Services and Settlement Variances found in article 490 of the Accounting Procedures Handbook, SLHI discovered that both RCVA Retail and RCVA STR were being recorded in the same Account 1518.

b) SLHI reviewed all revenues and expenses for accounts 4082, 4084 and 5315 and reclassified amounts to either RCVA account 1518 or 1548 as set out in article 490. The result is a balance as of December 31, 2012 for 1518 RCVA Retail of $4,047, and for 1548 RCVA STR of $8,236, for a total variance from the amount reported as at December 31, 2012 in RCVA Retail 1518 of $1,462($12,283 - $10,821). This variance is a result of interest calculations, the total principle amount remains unchanged. SLHI has filed excel workbook entitled “Sioux Lookout_IRR-9Staff28” to support these figures.

c) SLHI confirms that all costs incorporated into variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.

9-Staff-29

Ref: Exhibit 9/Tab 2/Sch. 4/p.2

With respect to the Deferral/Variance Account Workform provided in Table 9-29:

a) Please explain which allocators were used for Group 2 accounts.

b) Please explain how the “Amounts from Sheet 2” in Table 9-29 were allocated across rate classes.

SLHI Response

a) With reference to the workform "Sioux Lookout_2013_EDDVAR_Continuity Schedule_CoS_V2_20130222" Sheet 5, and Table 9.29, SLHI inadvertently did not include any allocators for Group 2 Accounts. SLHI has updated the workform using the default allocators set out in the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)* issued July 31, 2009 for Group 2 accounts. The workform has also been updated with the adjustment to Accounts 1518 and 1548 from the previous interrogatory. SLHI has filed the amended workform entitled Sioux Lookout_2013_EDDVAR_Continuity Schedule_Cos_V2_20130501 with these interrogatories.

b) Table 9-29 has been updated as stated in (a) above and supplied at the end of this section.

9-Staff-30

Ref: Exhibit 9/Tab 2/Sch. 1/p. 5

SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 in the amount of $17,843, and to keep the sub-account open and request disposition of additional balances at its next Cost of Service Application.

a) Please provide a breakdown of the costs recorded in Account 1508 Other Regulatory Assets, Sub-Account Deferred IFRS Transition Costs. Please complete Appendix 2-U. Please provide an explanation for each category of costs recorded in Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs. SLHI must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.

b) With regards to 1508, Other Regulatory Assets, "Sub-account Deferred IFRS Transition Costs", October 2009 Accounting Procedures Handbook ("APH") FAQ #2 states:

   "In the distributor's next cost of service rate application immediately after the IFRS transition period, the balance in this sub account should be included for review and disposition"

   i. Please state SLHI's justification for the disposition of the IFRS transition costs in this rate application and not the rate application immediately after the IFRS transition period.
   ii. If disposition is still being requested by SLHI, please indicate if SLHI plans to continue accumulating costs in Account 1508 from 2012 onwards.
   iii. If disposition is not requested, please update the relevant evidence in the application.

SLHI Response

a) The total principle amount of $17,500 is for consulting fees paid to the same firm to analyse SLHI's Distribution Plant assets and provide a breakdown of the opening balances upon transition to IFRS (at the time it would have been January 1, 2011 balances). The firm was engaged specifically for the purpose of providing IFRS transition services and would therefore meet the requirement of one-time IFRS administrative incremental costs. Appendix 2-U is correct as originally filed.

b) i. SLHI feels that since the deferral of IFRS could be extended past 2015, it would be reasonable to dispose of the amount in this proceeding.
ii. SLHI would most likely incur additional one-time IFRS implementation costs closer to the transition date.
iii. Not applicable.

9-Staff-31

Ref: Exhibit 9/Tab 2/Sch. 1/p.5

a) As at December 31, 2011, please indicate the percentage of completion of SLHI's IFRS project.

b) Please indicate the remaining costs SLHI incurred in 2012 and expected to incur in 2013 and beyond to complete the IFRS project.

SLHI Response

a) As at December 31, 2011, SLHI estimates that 70% of the IFRS project is complete. This is based on the breakdown of the NBVs of the assets for the opening balances as at January 1, 2011. Upon the transition to IFRS, SLHI will have to update the values to the year in which transition is required. SLHI will also have to address any decisions made with respect to regulatory assets and expects a consultant will be required for guidance.

b) SLHI incurred an additional $6,500 in the first part of 2012. These fees were paid to the consultant mentioned in 9-Staff-30 and were for the completion of the work to provide opening balances for January 1, 2011. In light of the recent announcement to defer adoption for rate regulated entities to January 1, 2015, SLHI does not expect to incur any additional costs in 2013.

9-Staff-32

Ref: Exhibit 9/Tab 2/Sch. 1/p. 7

FAQ #4 of the December 2010 APH-FAQs, states:

"Any alternative method to determine and record incremental ITCs must yield similar results so that there is no material difference between results from the alternative methods and the amounts that would be derived from a transactional analysis."

a) Please provide detailed schedules, similar to Table 1 and Table 2 of FAQ #4 of the December 2010 APH-FAQs, to indicate the period HST savings on OM&A costs and capital expenditures for the following periods: (Note: 2010 and 2011 are already provided)
   i. January 1, 2012 to December 31, 2012 (Actual); and
   ii. January 1, 2013 to April 30, 2013 (Forecast)

b) Please update the balance in Account 1592 to be cleared and associated rate design with a principal balance to April 30, 2013 plus carrying charges.

c) SLHI has already incurred actual amounts for the year 2012 and the first three months of 2013. SLHI only requires a forecasted principal balance of one month to April 30, 2013. Please provide reasons as to why the Sub-account of Account 1592 cannot be cleared on a final basis with a principal amount as at April 30, 2013 and associated carrying charges to April 30, 2013.

SLHI Response

a) As stated in Exhibit 9/Tab 2/ Schedule 1/page 10/line 2, SLHI has calculated the ITCs on a transactional basis, and did not use an alternative method. See below for the HST savings on OM&A and capital expenditures for January 1, 2012 to December 31, 2012 (actual) and January 1, 2013 to April 30, 2013 (forecast):

HST Savings: January 1, 2012 to December 31, 2012	
	2012 Actual HST Savings
OM&A	14,562
Capital	80
Interest	294
Total HST Savings	14,936
50% Refund to Customers	**7,468**
Actual purchases	
OM&A	182020
Capital	248957
Total	430977

HST Savings: January 1, 2013 to April 30, 2013	
	2013 Forecasted Savings
OM&A	2812
Capital	78
Interest	178
Total HST Savings	3,068
50% Refund to Customers	**1,534**
Actual purchases	
OM&A	35151
Capital	103098
Total	138249

b) See below for the updated Table 9-21: HST Savings by Year with the balance in Account 1592 updated with the principal balance to April 30, 2013 plus carrying charges. The amount has also been updated in the Sioux Lookout_2013_EDDVAR_Continuity Schedule_Cos_V2_20130501.

Table 9-21: HST Savings by Year					
	2010 Actual HST Savings	2011 Actual Savings	2012 Actual Savings	2013 Forecasted Savings	Grand Total
OM&A	3,544	9,058	14,562	2812	**29,976**
Capital	84	59	80	78	**301**
Interest	27	114	294	178	**613**
Total HST Savings	3,655	9,231	14,936	3,068	**30,890**
50% Refund to Customers					**15,445**
Actual purchases					
OM&A	44306	113223	182020	35151	
Capital	212172	194252	248957	103098	
Total	256478	307475	430977	138249	

c) SLHI has no issues with clearing the Sub-account of Account 1592 with a principal amount as at April 30, 2013 and associated carrying charges to April 30, 2013.

Below are the updated Table 9-29: Deferral/Variance Account Workform and Table 9-30: 2013 Deferral and Variance Account Rate Rider by Class with changes made for Exhibit 9 interrogatories.

Table 9-29: Deferral/Variance Account Workform

		Amounts from Sheet 2	Allocator	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Street Lighting
LV Variance Account	1550	17,221	kWh	7,703	2,974	6,424	4	117
RSVA - Wholesale Market Service Charge	1580	(84,441)	kWh	(37,768)	(14,583)	(31,497)	(18)	(576)
RSVA - Retail Transmission Network Charge	1584	1,755	kWh	785	303	655	0	12
RSVA - Retail Transmission Connection Charge	1586	(15,952)	kWh	(7,135)	(2,755)	(5,950)	(3)	(109)
RSVA - Power (excluding Global Adjustment)	1588	42,042	kWh	18,804	7,261	15,682	9	287
RSVA - Power - Sub-account - Global Adjustment	1588	(68,906)	Non-RPP kWh	(4,500)	(441)	(62,713)	0	(1,251)
Recovery of Regulatory Asset Balances	1590	0	kWh	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	(47,485)	kWh	(21,238)	(8,201)	(17,712)	(10)	(324)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	kWh	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(153,167)	kWh	(68,507)	(26,452)	(57,131)	(33)	(1,044)
Total of Group 1 Accounts (excluding 1588 sub-account)		**(240,026)**		**(107,356)**	**(41,452)**	**(89,530)**	**(51)**	**(1,637)**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0		0	0	0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0		0	0	0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	17,843	Distribution Rev.	9,914	3,272	4,293	32	332
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0		0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0		0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0		0	0	0	0	0
Retail Cost Variance Account - Retail	1518	5,475	# of Customers	3,867	631	87	5	885
Misc. Deferred Debits	1525	0		0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	0		0	0	0	0	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0	0	0
Smart Grid OM&A Deferral Account	1535	0		0	0	0	0	0
Smart Grid Funding Adder Deferral Account	1536	0		0	0	0	0	0
Retail Cost Variance Account - STR	1548	8,307	# of Customers	5,868	957	131	8	1,343
Board-Approved CDM Variance Account	1567	0		0	0	0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0	0	0
RSVA - One-time	1582	0		0	0	0	0	0
Other Deferred Credits	2425	0		0	0	0	0	0
Total of Group 2 Accounts		**31,625**		**19,649**	**4,860**	**4,511**	**45**	**2,561**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0		0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(15,445)	kWh	(6,908)	(2,667)	(5,761)	(3)	(105)
Total of Account 1562 and Account 1592		**(15,445)**		**(6,908)**	**(2,667)**	**(5,761)**	**(3)**	**(105)**
Special Purpose Charge Assessment Variance Account	1521	0		0	0	0	0	0
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0						
(Account 1568 - total amount allocated to classes)		0						
Variance		0						
Total Balance Allocated to each class (excluding 1588 sub-account)		**(223,845)**		**(94,615)**	**(39,259)**	**(90,780)**	**(10)**	**819**
Total Balance in Account 1588 - sub account		**(68,906)**		**(4,500)**	**(441)**	**(62,713)**	**0**	**(1,251)**
Total Balance Allocated to each class (including 1588 sub-account)		**(292,751)**		**(99,115)**	**(39,700)**	**(153,493)**	**(10)**	**(433)**

Table 9-30: 2013 Deferral and Variance Account Rate Rider by Class				
Rate Class	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts
Residential	kWh	32,694,600	-$94,615	-0.0029
General Service Less Than 50 kW	kWh	12,624,003	-$39,259	-0.0031
General Service 50 to 4,999 kW	kW	66,653	-$90,780	-1.3620
Unmetered Scattered Load	kWh	15,597	-$10	-0.0006
Street Lighting	kW	1,446	$819	0.5660
Total			**-$223,845**	

APPENDIX A

Adjustments Tracking Sheet		
Reference IR#	**Item Description**	**Area of Change**
2-VECC-3	Updated Table 2.17 for actual 2012 Capital Expenditures	Rate Base
2-VECC-3	Updated Appendix 2-A in Chapter 2 Appendices for actual 2012 project completions	Rate Base
2-VECC-4	Updated Appendices 2-B for 2012 and 2013 in Chapter 2 Appendices and Tables 2.6 and 2.7 Fixed Asset Continuity Statements	Rate Base
2-Staff-9	Updated cost of power forecast for 2013 to include the new rates for WMS and RRRP and included the Smart Meter Entity Charge in the total Cost of Power	Cost of Power/Rate Base
5-Staff-23/5-VECC-30	Updated Table 5.1 for 2013, Appendix 2-OA in the Chapter 2 Appendices and The RRWF for the updated Cost of Capital parameters.	Cost of Capital and Rate of Return
9-Staff-8	Corrected amounts in RCVA Accounts 1518 and 1548	Deferral and Variance Accounts
9-Staff-27	Amended SMRR for Residential and GS < 50	Deferral and Variance Accounts
9-Staff-29	Updated EDDVAR Work form with above corrections and added allocators to Group 2 Accounts	Deferral and Variance Accounts
9-Staff-32	Updated Account 1592 with principal and associated carry charges to April 30, 2013 in EDDVAR Workform	Deferral and Variance Accounts

APPENDIX B – RATE IMPACTS

Customer Class: **Residential**

Consumption 800 **kWh** ☐ May 1 - October 31 ☒ November 1 - April 30 (Select this radio button for applications filed af

	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	$ 24.2600	1	$ 24.26	$ 29.0200	1	$ 29.02	$ 4.76	19.62%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 4.6100	1	$ 4.61		1	$ -	-$ 4.61	-100.00%
Smart Meter Disposition Rider	Monthly	$ 2.4200	1	$ 2.42	$ 2.4200	1	$ 2.42	$ -	0.00%
Smart Asset Recovery Rider	Monthly		1	$ -	$ 2.7400	1	$ 2.74	$ 2.74	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0104	800	$ 8.32	$ 0.0124	800	$ 9.92	$ 1.60	19.23%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
Low Voltage Rate Adder	per kWh	$ 0.0030	800	$ 2.40	$ 0.0037	800	$ 2.96	$ 0.56	23.33%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 42.01			$ 47.06	**$ 5.05**	**12.02%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0035	800	-$ 2.80	-$ 0.0029	800	-$ 2.32	$ 0.48	-17.14%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge			800	$ -		800	$ -	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 39.21**			**$ 44.74**	**$ 5.53**	**14.10%**
RTSR - Network	per kWh	$ 0.0055	851	$ 4.68	$ 0.0065	872	$ 5.67	$ 0.98	21.01%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	851	$ 1.11	$ 0.0015	872	$ 1.31	$ 0.20	18.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 45.00**			**$ 51.71**	**$ 6.71**	**14.92%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	851	$ 4.43	$ 0.0044	872	$ 3.84	-$ 0.59	-13.36%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	851	$ 0.94	$ 0.0012	872	$ 1.05	$ 0.11	11.70%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	851	$ 5.96	$ 0.0070	872	$ 6.10	$ 0.14	2.40%
Energy - RPP - Tier 1	per kWh	$ 0.0740	851	$ 63.00	$ 0.0740	872	$ 64.51	$ 1.51	2.40%
Energy - RPP - Tier 2	per kWh	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	545	$ 34.33	$ 0.0630	558	$ 35.15	$ 0.82	2.40%
TOU - Mid Peak	per kWh	$ 0.0990	153	$ 15.17	$ 0.0990	157	$ 15.53	$ 0.36	2.40%
TOU - On Peak	per kWh	$ 0.1180	153	$ 18.08	$ 0.1180	157	$ 18.52	$ 0.43	2.40%
Total Bill on RPP (before Taxes)				**$ 119.57**			**$ 127.46**	**$ 7.89**	**6.59%**
HST		13%		$ 15.54	13%		$ 16.57	$ 1.03	6.59%
Total Bill (including HST)				$ 135.12			$ 144.03	$ 8.91	6.59%
Ontario Clean Energy Benefit [1]				-$ 13.51			-$ 14.40	-$ 0.89	6.59%
Total Bill on RPP (including OCEB)				**$ 121.61**			**$ 129.63**	**$ 8.02**	**6.60%**
Total Bill on TOU (before Taxes)				**$ 124.15**			**$ 132.15**	**$ 8.00**	**6.44%**
HST		13%		$ 16.14	13%		$ 17.18	$ 1.04	6.44%
Total Bill (including HST)				$ 140.29			$ 149.33	$ 9.03	6.44%
Ontario Clean Energy Benefit [1]				-$ 14.03			-$ 14.93	-$ 0.90	6.41%
Total Bill on TOU (including OCEB)				**$ 126.26**			**$ 134.40**	**$ 8.13**	**6.44%**

Loss Factor (%) Current: 6.42% Proposed: 8.97%

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

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

	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	$ 43.1100	1	$ 43.11	$ 45.8200	1	$ 45.82	$ 2.71	6.29%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 5.1800	1	$ 5.18		1	$ -	-$ 5.18	-100.00%
Smart Meter Disposition Rider	Monthly	$ 3.0900	1	$ 3.09	$ 3.0900	1	$ 3.09	$ -	0.00%
Smart Meter Disposition Rider	Monthly		1	$ -	$ 3.2400	1	$ 3.24	$ 3.24	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0082	2000	$ 16.40	$ 0.0087	2000	$ 17.40	$ 1.00	6.10%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider			2000	$ -		2000	$ -	$ -	
Low Voltage Rate Adder	per kWh	$ 0.0027	2000	$ 5.40	$ 0.0031	2000	$ 6.20	$ 0.80	14.81%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 73.18			$ 75.75	**$ 2.57**	**3.51%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0028	2000	-$ 5.60	-$ 0.0031	2000	-$ 6.20	-$ 0.60	10.71%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge			2000	$ -		2000	$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 67.58**			**$ 69.55**	**$ 1.97**	**2.92%**
RTSR - Network	per kWh	$ 0.0050	2128	$ 10.64	$ 0.0059	2179	$ 12.86	$ 2.22	20.83%
RTSR - Line and Transformation Connection	per kWh	$ 0.0011	2128	$ 2.34	$ 0.0012	2179	$ 2.62	$ 0.27	11.70%
Sub-Total C - Delivery (including Sub-Total B)				**$ 80.56**			**$ 85.02**	**$ 4.46**	**5.54%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2128	$ 11.07	$ 0.0044	2179	$ 9.59	-$ 1.48	-13.36%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2128	$ 2.34	$ 0.0012	2179	$ 2.62	$ 0.27	11.70%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2128	$ 14.90	$ 0.0070	2179	$ 15.26	$ 0.36	2.40%
Energy - RPP - Tier 1	per kWh	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0870	1128	$ 98.17	$ 0.0870	1179	$ 102.61	$ 4.44	4.52%
TOU - Off Peak	per kWh	$ 0.0630	1362	$ 85.82	$ 0.0630	1395	$ 87.87	$ 2.06	2.40%
TOU - Mid Peak	per kWh	$ 0.0990	383	$ 37.93	$ 0.0990	392	$ 38.84	$ 0.91	2.40%
TOU - On Peak	per kWh	$ 0.1180	383	$ 45.21	$ 0.1180	392	$ 46.29	$ 1.08	2.40%
Total Bill on RPP (before Taxes)				**$ 281.29**			**$ 289.34**	**$ 8.05**	**2.86%**
HST		13%		$ 36.57	13%		$ 37.61	$ 1.05	2.86%
Total Bill (including HST)				$ 317.86			$ 326.96	$ 9.10	2.86%
Ontario Clean Energy Benefit [1]				-$ 31.79			-$ 32.70	-$ 0.91	2.86%
Total Bill on RPP (including OCEB)				**$ 286.07**			**$ 294.26**	**$ 8.19**	**2.86%**
Total Bill on TOU (before Taxes)				**$ 278.07**			**$ 285.73**	**$ 7.66**	**2.76%**
HST		13%		$ 36.15	13%		$ 37.15	$ 1.00	2.76%
Total Bill (including HST)				$ 314.22			$ 322.88	$ 8.66	2.76%
Ontario Clean Energy Benefit [1]				-$ 31.42			-$ 32.29	-$ 0.87	2.77%
Total Bill on TOU (including OCEB)				**$ 282.80**			**$ 290.59**	**$ 7.79**	**2.75%**

Loss Factor (%) Current: 6.42% Proposed: 8.97%

Customer Class: **General Service 50 to 4,999 kW**

Consumption 100 **kW** / 30000 kWh — May 1 - October 31 / November 1 - April 30 (Select this radio button for applications filed afte

	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	$ 398.8800	1	$ 398.88	$ 383.6100	1	$ 383.61	-$ 15.27	-3.83%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.3832	100	$ 138.32	$ 1.3337	100	$ 133.37	-$ 4.95	-3.58%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider			100	$ -		100	$ -	$ -	
Low Voltage Rate Adder	per kW	$ 1.1187	100	$ 111.87	$ 1.2890	100	$ 128.90	$ 17.03	15.22%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A				$ 649.07			$ 645.88	**-$ 3.19**	**-0.49%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.8074	100	-$ 80.74	-$ 1.3620	100	-$ 136.20	-$ 55.46	68.69%
Global Adjustment Rate Rider	per kW	-$ 0.8145	100	-$ 81.45	-$ 1.0352	100	-$ 103.52	-$ 22.07	27.10%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge			100	$ -		100	$ -	$ -	
Smart Meter Entity Charge						100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 486.88**			**$ 406.16**	**-$ 80.72**	**-16.58%**
RTSR - Network	per kW	$ 2.0041	100	$ 200.41	$ 2.3692	100	$ 236.92	$ 36.51	18.22%
RTSR - Line and Transformation Connection	per kW	$ 0.4581	100	$ 45.81	$ 0.5163	100	$ 51.63	$ 5.82	12.70%
Sub-Total C - Delivery (including Sub-Total B)				**$ 733.10**			**$ 694.71**	**-$ 38.39**	**-5.24%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	31926	$ 166.02	$ 0.0044	32691	$ 143.84	-$ 22.17	-13.36%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	31926	$ 35.12	$ 0.0012	32691	$ 39.23	$ 4.11	11.70%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	30000	$ 210.00	$ 0.0070	30000	$ 210.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0870	30926	$ 2,690.56	$ 0.0870	31691	$ 2,757.12	$ 66.56	2.47%
TOU - Off Peak	per kWh	$ 0.0630	20433	$ 1,287.26	$ 0.0630	20922	$ 1,318.10	$ 30.84	2.40%
TOU - Mid Peak	per kWh	$ 0.0990	5747	$ 568.92	$ 0.0990	5884	$ 582.55	$ 13.63	2.40%
TOU - On Peak	per kWh	$ 0.1180	5747	$ 678.11	$ 0.1180	5884	$ 694.36	$ 16.25	2.40%
Total Bill on RPP (before Taxes)				**$ 3,909.05**			**$ 3,919.15**	**$ 10.10**	**0.26%**
HST		13%		$ 508.18	13%		$ 509.49	$ 1.31	0.26%
Total Bill (including HST)				$ 4,417.22			$ 4,428.64	$ 11.41	0.26%
Ontario Clean Energy Benefit [1]				-$ 441.72			-$ 442.86	-$ 1.14	0.26%
Total Bill on RPP (including OCEB)				**$ 3,975.50**			**$ 3,985.78**	**$ 10.27**	**0.26%**
Total Bill on TOU (before Taxes)				**$ 3,678.77**			**$ 3,683.04**	**$ 4.27**	**0.12%**
HST		13%		$ 478.24	13%		$ 478.80	$ 0.56	0.12%
Total Bill (including HST)				$ 4,157.01			$ 4,161.84	$ 4.83	0.12%
Ontario Clean Energy Benefit [1]				-$ 415.70			-$ 416.18	-$ 0.48	0.12%
Total Bill on TOU (including OCEB)				**$ 3,741.31**			**$ 3,745.66**	**$ 4.35**	**0.12%**

Loss Factor (%) — Current: 6.42% — Proposed: 8.97%

Customer Class: **Street Lighting**

Consumption 120 **kW** ☐ May 1 - October 31 ☒ November 1 - April 30 (Select this radio button for applications filed after

40000 kWh

531 Connections

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.8700	531	$ 5,240.97	$ 9.8600	531	$ 5,235.66	-$ 5.31	-0.10%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 26.0218	120	$ 3,122.62	$ 26.0007	120	$ 3,120.08	-$ 2.53	-0.08%
Smart Meter Disposition Rider			120	$ -		120	$ -	$ -	
LRAM & SSM Rate Rider			120	$ -		120	$ -	$ -	
Low Voltage Rate Adder	per kW	$ 0.8534	120	$ 102.41	$ 0.9966	120	$ 119.59	$ 17.18	16.78%
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
Sub-Total A				$ 8,465.99			$ 8,475.34	**$ 9.34**	**0.11%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 2.1406	120	-$ 256.87	$ 0.5660	120	$ 67.92	$ 324.79	-126.44%
Global Adjustment Rate Rider			120	$ -	-$ 0.8723	120	-$ 104.68	-$ 104.68	
			120	$ -		120	$ -	$ -	
			120	$ -		120	$ -	$ -	
Low Voltage Service Charge			120	$ -		120	$ -	$ -	
Smart Meter Entity Charge						120	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8,209.12**			**$ 8,438.58**	**$ 229.46**	**2.80%**
RTSR - Network	per kW	$ 1.5114	120	$ 181.37	$ 1.7868	120	$ 214.42	$ 33.05	18.22%
RTSR - Line and Transformation Connection	per kW	$ 0.3542	120	$ 42.50	$ 0.3992	120	$ 47.90	$ 5.40	12.70%
Sub-Total C - Delivery (including Sub-Total B)				**$ 8,432.99**			**$ 8,700.90**	**$ 267.91**	**3.18%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	42568	$ 221.35	$ 0.0044	43588	$ 191.79	-$ 29.57	-13.36%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	42568	$ 46.82	$ 0.0012	43588	$ 52.31	$ 5.48	11.70%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	40000	$ 280.00	$ 0.0070	40000	$ 280.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0870	41568	$ 3,616.42	$ 0.0870	42588	$ 3,705.16	$ 88.74	2.45%
TOU - Off Peak	per kWh	$ 0.0630	27244	$ 1,716.34	$ 0.0630	27896	$ 1,757.47	$ 41.13	2.40%
TOU - Mid Peak	per kWh	$ 0.0990	7662	$ 758.56	$ 0.0990	7846	$ 776.74	$ 18.18	2.40%
TOU - On Peak	per kWh	$ 0.1180	7662	$ 904.14	$ 0.1180	7846	$ 925.81	$ 21.66	2.40%
Total Bill on RPP (before Taxes)				**$ 12,671.84**			**$ 13,004.40**	**$ 332.56**	**2.62%**
HST		13%		$ 1,647.34	13%		$ 1,690.57	$ 43.23	2.62%
Total Bill (including HST)				$ 14,319.18			$ 14,694.97	$ 375.79	2.62%
Ontario Clean Energy Benefit [1]				-$ 1,431.92			-$ 1,469.50	-$ 37.58	2.62%
Total Bill on RPP (including OCEB)				**$ 12,887.26**			**$ 13,225.47**	**$ 338.21**	**2.62%**
Total Bill on TOU (before Taxes)				**$ 12,360.47**			**$ 12,685.26**	**$ 324.79**	**2.63%**
HST		13%		$ 1,606.86	13%		$ 1,649.08	$ 42.22	2.63%
Total Bill (including HST)				$ 13,967.33			$ 14,334.34	$ 367.01	2.63%
Ontario Clean Energy Benefit [1]				-$ 1,396.73			-$ 1,433.43	-$ 36.70	2.63%
Total Bill on TOU (including OCEB)				**$ 12,570.60**			**$ 12,900.91**	**$ 330.31**	**2.63%**

	Current	Proposed
Loss Factor (%)	6.42%	8.97%

Customer Class: **Unmetered Scattered Load**

Consumption 498 **kWh** ☐ May 1 - October 31 ☒ November 1 - April 30 (Select this radio button for applications filed af

	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	$ 21.5000	1	$ 21.50	$ 23.8500	1	$ 23.85	$ 2.35	10.93%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0083	498	$ 4.13	$ 0.0092	498	$ 4.58	$ 0.45	10.84%
Smart Meter Disposition Rider			498	$ -		498	$ -	$ -	
LRAM & SSM Rate Rider			498	$ -		498	$ -	$ -	
Low Voltage Rate Adder	per kWh	$ 0.0027	498	$ 1.34	$ 0.0031	498	$ 1.54	$ 0.20	14.81%
			498	$ -		498	$ -	$ -	
			498	$ -		498	$ -	$ -	
			498	$ -		498	$ -	$ -	
			498	$ -		498	$ -	$ -	
			498	$ -		498	$ -	$ -	
			498	$ -		498	$ -	$ -	
Sub-Total A				$ 26.98			$ 29.98	**$ 3.00**	**11.11%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0081	498	-$ 4.03	-$ 0.0006	498	-$ 0.30	$ 3.74	-92.59%
			498	$ -		498	$ -	$ -	
			498	$ -		498	$ -	$ -	
			498	$ -		498	$ -	$ -	
Low Voltage Service Charge			498	$ -		498	$ -	$ -	
Smart Meter Entity Charge						498	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.94**			**$ 29.68**	**$ 6.73**	**29.34%**
RTSR - Network	per kWh	$ 0.0050	530	$ 2.65	$ 0.0059	543	$ 3.20	$ 0.55	20.83%
RTSR - Line and Transformation Connection	per kWh	$ 0.0011	530	$ 0.58	$ 0.0012	543	$ 0.65	$ 0.07	11.70%
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.18**			**$ 33.53**	**$ 7.35**	**28.09%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	530	$ 2.76	$ 0.0044	543	$ 2.39	-$ 0.37	-13.36%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	530	$ 0.58	$ 0.0012	543	$ 0.65	$ 0.07	11.70%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	530	$ 3.71	$ 0.0070	543	$ 3.80	$ 0.09	2.40%
Energy - RPP - Tier 1	per kWh	$ 0.0740	530	$ 39.22	$ 0.0740	543	$ 40.16	$ 0.94	2.40%
Energy - RPP - Tier 2	per kWh	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	339	$ 21.37	$ 0.0630	347	$ 21.88	$ 0.51	2.40%
TOU - Mid Peak	per kWh	$ 0.0990	95	$ 9.44	$ 0.0990	98	$ 9.67	$ 0.23	2.40%
TOU - On Peak	per kWh	$ 0.1180	95	$ 11.26	$ 0.1180	98	$ 11.53	$ 0.27	2.40%
Total Bill on RPP (before Taxes)				**$ 72.69**			**$ 80.77**	**$ 8.08**	**11.12%**
HST		13%		$ 9.45	13%		$ 10.50	$ 1.05	11.12%
Total Bill (including HST)				$ 82.14			$ 91.28	$ 9.13	11.12%
Ontario Clean Energy Benefit [1]				-$ 8.21			-$ 9.13	-$ 0.92	11.21%
Total Bill on RPP (including OCEB)				**$ 73.93**			**$ 82.15**	**$ 8.21**	**11.11%**
Total Bill on TOU (before Taxes)				**$ 75.54**			**$ 83.69**	**$ 8.15**	**10.79%**
HST		13%		$ 9.82	13%		$ 10.88	$ 1.06	10.79%
Total Bill (including HST)				$ 85.37			$ 94.57	$ 9.21	10.79%
Ontario Clean Energy Benefit [1]				-$ 8.54			-$ 9.46	-$ 0.92	10.77%
Total Bill on TOU (including OCEB)				**$ 76.83**			**$ 85.11**	**$ 8.29**	**10.79%**

Loss Factor (%)	6.42%	8.97%