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

February 22, 2013

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

Dear Ms. Walli:

Re: Sioux Lookout Hydro Inc. – 2013 Cost of Service Electricity Distribution Rate Application EB-2012-0165

Sioux Lookout Hydro Inc. ("SLHI") is applying for authorization to adjust its current electricity distribution rates in accordance with its 2013 Cost of Service Electricity Distribution Rate Application.

In support of its Application Sioux Lookout Hydro Inc. utilized the following excel files to calculate the requested adjusted rates:

- 2013 Revenue Requirement Workform, Version 3.0
- 2013 Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 2 Appendices, Version 1.1
- Income Tax/PILs Workform for 2013 Filers, Version 2.0
- RTSR Workform for Electricity Distributors (2013 Filers), Version 3.0
- Deferral/Variance Account Workform for 2013 Filers, Version 2.0
- 2013 Cost Allocation Model, Version 3.0
- 2011 OPA Final Evaluation Report
- 2013 Load Forecast

Please find enclosed two hard copies of Sioux Lookout Hydro Inc.'s 2013 Cost of Service Electricity Distribution Rate Application. An electronic version of this application has been submitted through the e-Filing Services and emailed to the Board Secretary.

If you require any further information, please contact the undersigned at (807)737-3800 or via email at dkulchyski@tbaytel.net.

Sincerely,

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

2013 COST OF SERVICE
ELECTRICITY DISTRIBUTION
RATE APPLICATION

ED-2002-0514
EB-2012-0165

February 22, 2013

SIOUX LOOKOUT HYDRO INCORPORATED
25 FIFTH AVENUE, P.O. BOX 908
SIOUX LOOKOUT, ON P8T 1B3

SIOUX LOOKOUT HYDRO INC.

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES EFFECTIVE MAY 1, 2013

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IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15, as amended;

AND IN THE MATTER OF an Application by Sioux Lookout Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2013.

Title of Proceeding:	An Application by Sioux Lookout Hydro Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2013.
Applicants Name:	Sioux Lookout Hydro Inc.
Applicants Address:	25 Fifth Ave., PO Box 908 Sioux Lookout, ON P8T 1B3
Applicants Contacts:	Deanne Kulchyski, President/CEO Email: dkulchyski@tbaytel.net Phone: (807)737-3800 Fax: (807)737-2832

APPLICATION

Introduction

The Applicant is Sioux Lookout Hydro Inc. (SLHI) The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Municipality of Sioux Lookout, ON. The Applicant carries on the business of distributing electricity within the Municipality of Sioux Lookout.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the Ontario Energy Board Act, 1998 ("the OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2013. A list of requested approvals is set out below.

Except where specifically identified in the Application, the Applicant followed the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, update issued June 28, 2012 (the "Filing Requirements") in order to prepare this application.

SLHI's President/CEO certifies that the evidence filed in the application is accurate to the best of her knowledge and belief.

Publication of Notice

The Applicant proposes to publish the notice through the local "The Sioux Lookout Bulletin" newspaper which is a weekly publication with a circulation of approximately 4,444 copies per week.

Proposed Distribution Rates and Other Charges

The Schedule of Proposed Tariff of Rates and Charges in this Application is set out in Table 1.1 below. The material being filed in support of this Application sets out Sioux Lookout Hydro Inc.'s approach to its distribution rates and charges.

Proposed Effective Date of Rate Order

The Applicant requests that the OEB make its Rate Order effective May 1, 2013 in accordance with the Filing Requirements.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

The proposed rates, as set out in Table 1.1, for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

The proposed and adjusted rates are necessary to ensure SLHI. has sufficient funds to meet its capital expenditure obligations, fund OM&A expenses, provide for a reasonable Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILS");

There are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures.

The other specific service charges proposed by the Applicant are the same as those previously approved by the OEB; and

Such other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2013.

The Applicant seeks approval of its Basic Green Energy Plan as part of this Application in accordance with the Deemed Conditions of License as reported by the OEB in its Distribution System Planning Guidelines G-2009-0087, issued June 16, 2009. The Applicant's Basic Green Energy Plan has been prepared in accordance with the OEB's Filing Requirements as reported in EB-2009-0397 – Distribution System Plans under the Green Energy Act issued on December 18, 2009.

The 2013 Operating Budget was approved by the Sioux Lookout Hydro Board of Directors on August 30, 2012 and the Capital Budget was approved on November 28, 2012.

Form of Hearing Requested

The Applicant requests that this Application be disposed of by way of a written hearing.

DATED at Sioux lookout, Ontario, this 20th day of February, 2013.

All of which is respectfully submitted,

Sioux Lookout Hydro Inc.

Deanne Kulchyski, President/CEO

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

Sioux Lookout Hydro Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective May 1, 2013

EB-2012-0165

MONTHLY RATES AND CHARGES

Applied For Monthly Rates and Charges

Residential

Monthly Rates and Charges - Delivery Component

Service Charge	$	28.52
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until August 31, 2014	$	2.42
Stranded Asset Rate Rider - Effective until April 30, 2015	$	2.83
Distribution Volumetric Rate	$/kWh	0.0122
Rate Rider for Deferral/Variance Account Disposition (2013) - Effective until April 30, 2014	$/kWh	(0.00280)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.00250)
Low Voltage Volumetric Rate	$/kWh	0.0037
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0015

Monthly Rates and Charges - Regulatory Component

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

General Service Less Than 50 kW

Monthly Rates and Charges - Delivery Component

Service Charge	$	44.98
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until August 31, 2014	$	3.09
Stranded Asset Rate Rider - Effective until April 30, 2015		2.63
Distribution Volumetric Rate	$/kWh	0.0086
Rate Rider for Deferral/Variance Account Disposition (2013) - Effective until April 30, 2014	$/kWh	(0.0031)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0025)
Low Voltage Volumetric Rate	$/kWh	0.0031
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0012

Monthly Rates and Charges - Regulatory Component

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

General Service 50 to 4,999 kW

Monthly Rates and Charges - Delivery Component

Service Charge	$	375.80
Distribution Volumetric Rate	$/kW	1.3085
Rate Rider for Deferral/Variance Account Disposition (2013) - Effective until April 30, 2014	$/kW	(1.3376)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - Effective until April 30, 2014	$/kW	(1.0352)
Applicable only for Non-RPP Customers		
Low Voltage Volumetric Rate	$/kW	1.2890
Retail Transmission Rate – Network Service Rate	$/kW	2.3692
Retail Transmission Rate – Network Service Rate – Interval metered > 1,000 kW	$/kW	2.5034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5163
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval metered > 1,000 kW	$/kW	0.5667

Monthly Rates and Charges - Regulatory Component

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

Unmetered Scattered Load

Service Charge (per connection)	$	23.56
Distribution Volumetric Rate	$/kWh	0.0091
Low Voltage Volumetric Rate	$/kWh	0.0031
Rate Rider for Deferral/Variance Account Disposition (2013) - Effective until April 30, 2014	$/kWh	(0.0019)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0012

Monthly Rates and Charges - Regulatory Component

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

Street Lighting

Service Charge (per connection)	$	9.67
Distribution Volumetric Rate	$/kW	25.4938
Low Voltage Volumetric Rate	$/kW	0.9966
Rate Rider for Deferral/Variance Account Disposition (2013) - Effective until April 30, 2014	$/kW	1.5062
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - Effective until April 30, 2014	$/kW	(0.8723)
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kW	1.7868
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.3992

Monthly Rates and Charges - Regulatory Component

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

microFIT Generator

Service Charge	$	5.40

Specific Service Charges

Customer Administration

Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	110.00
Disconnect/Reconnect at meter - after regular hours	$	245.00
Disconnect/Reconnect at pole - during regular hours	$	245.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Other

Install/Remove load control device - during regular hours	$	110.00
Install/Remove load control device - after regular hours	$	245.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.3741)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges (if applicable)

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

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

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0897
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0788
Total Loss Factor - Primary Metered Customer > 5,000 kW	

CONTACT INFORMATION:

SIOUX LOOKOUT HYDRO INC.

PRESIDENT/CEO:	Deanne Kulchyski, CGA, BComm(Hons)	
	Telephone:	807-737-3800
	Fax:	807-737-2832
	Email:	dkulchyski@tbaytel.net

SPECIFIC APPROVALS REQUESTED:

In this proceeding, SLHI is requesting the following approvals:

- Approval to charge rates effective May 1, 2013 to recover a revenue requirement of $2,091,430 which includes a revenue deficiency of $173,089 as set out in Exhibit 6, Tab 1, Schedule 1; the schedule of proposed rates is set out in Exhibit 1, Tab 1, Schedule 2, Appendix A;

- Approval of the proposed loss factor as set out in Exhibit 8, Schedule 1;

- Approval of revised low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8, Schedule 1;

- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8, Schedule 1;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of SLHI's 2012 Distribution Rates (EB-2011-0102);

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of SLHI's 2012 Distribution Rates (EB-EB-2011-0102);

- Approval to dispose of Variance account 1576 - Accounting Changes under CGAAP using the method of recovery described in Exhibit 2, Tab 5, Schedule 4.

- Approval to dispose of the following Group 1 and Group 2 Deferral and Variance Account balances as at December 31, 2011 plus forecasted interest to April 30, 2013 over a one year period using the method of recovery described in Exhibit 9, Tab 2, Schedule 4:

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

1518 Retail Cost Variance Account

1550 Low Voltage Variance

1580 RSVA - Wholesale Market Service Charges

1584 RSVA - Transmission Network

1586 RSVA - Transmission Connection

1588 RSVA - Power

1588 RSVA – Power Sub-Account Global Adjustment

1592 Pils and Tax Variances for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits (ITCs)

1595 Disposition and Recovery/Refund of Regulatory Balances (2008)

1595 Disposition and Recovery/Refund of Regulatory Balances (2010)

- In SLHI's 2011 IRM Decision (EB-2010-0238) The Board directed SLHI to record in account 1592 the incremental Input Tax Credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. SLHI has complied with this directive and has been recording these amounts as of July 1, 2010. The application SLHI is currently submitting is based on budgeted information net of any HST ITCs SLHI will receive. As a result, SLHI requests approval to discontinue recording these variances as of May 1, 2013.

- Approval to dispose of SLHI's stranded meter costs based on the estimated NBV of its stranded assets as at December 31, 2012 described in Exhibit 9, Tab 3, Schedule 1.

PROPOSED ISSUES LIST:

The Applicant would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2013 Test Year may constitute issues in this Application:

GENERAL (Exhibit 1)

- Are the Applicant's overall economic and business planning assumptions for the Test Year appropriate?
- Is service quality, based on the Board specified performance indicators, acceptable?
- Is the proposed revenue requirement appropriate?

2. RATE BASE (Exhibit 2)

- Are the Applicant's asset planning assumptions (e.g. asset condition, economic conditions, etc.) appropriate?
- Is the Applicant's capitalization and depreciation policy appropriate?
- Are the capital expenditures appropriate?
- Are the in-service dates accurate for projects closed prior to the Test Year and are they appropriate for proposed projects?
- Is the working capital allowance for the test year appropriate?
- Is the proposed rate base for the test year appropriate?
- Is the accounting for stranded meters appropriate?
- Is the Basic Green Energy Plan appropriate?

3. LOADS, CUSTOMERS - THROUGHPUT REVENUE (Exhibit 3)

- Is the load forecast methodology including weather normalization appropriate?
- Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?
- Is CDM appropriately reflected in the load forecast?
- Are the proposed revenue offsets appropriate?

4. OPERATING COSTS (Exhibit 4)

- Is the overall OM&A forecast for the test year appropriate?
- Are the methodologies used to allocate shared services and other costs appropriate?
- Is the proposed level of depreciation/amortization expense for the test year appropriate?
- Are the 2013 compensation costs and employee levels appropriate?
- Is the test year forecast of PILs appropriate?

5. COST OF CAPITAL AND RATE OF RETURN (Exhibit 5)

- Is the proposed capital structure appropriate?
- Is the cost of debt appropriate?
- Is the proposed return on equity appropriate?

6. CALCULATION OF REVENUE DEFICIENCY OR SURPLUS (Exhibit 6)

- Is the calculation of Revenue Deficiency accurate?

7. COST ALLOCATION (Exhibit 7)

- Is the Applicant’s cost allocation appropriate?
- Are the proposed revenue-to-cost ratios appropriate?

8. RATE DESIGN (Exhibit 8)

- Are the customer charges and the fixed-variable splits for each class appropriate?
- Are the proposed Retail Transmission Service Rates appropriate?
- Are the proposed loss factors appropriate?
- Is the Applicant’s proposed Tariff of Rates and Charges appropriate?
- Is the Applicant's rate mitigation plan appropriate?

9. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

- Are the account balances, cost allocation methodology and disposition plan appropriate?

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On January 26, 2012 the Board issued its list of distributors that it anticipates will be filing a Cost of Service Applications for 2013. Sioux Lookout Hydro Inc. was included on that list.

ACCOUNTING ORDERS REQUESTED:

SLHI is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

Sioux Lookout Hydro Inc. has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITY SERVED:	Urban and Rural areas of the Municipality of Sioux Lookout
URBAN AREAS:	6 sq km
TOTAL SERVICE AREA:	536 sq km
RURAL SERVICE AREA:	530 sq km
DISTRIBUTION TYPE:	Electricity distribution
MUNICIPAL POPULATION:	5,336
POPULATION OF URBAN AREAS SERVED:	5,336

A map of SLHI’s Distribution Service Territory accompanies this Schedule as Appendix B.

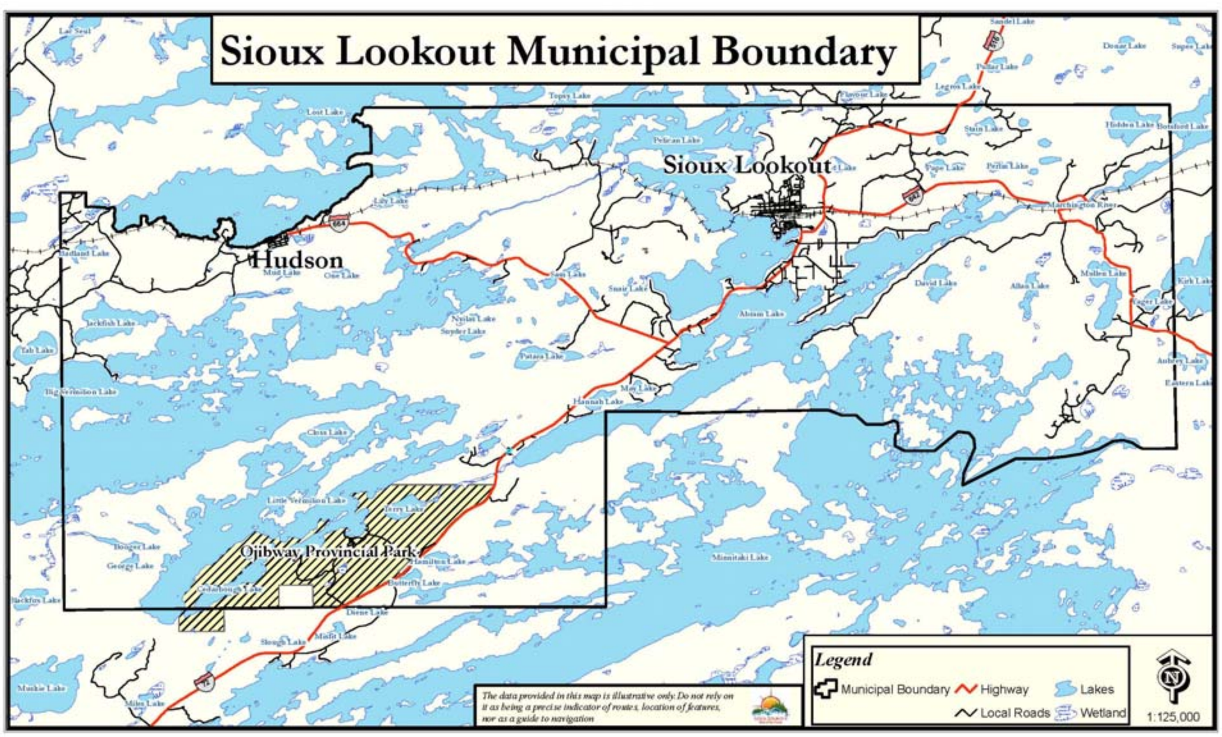
A schematic diagram of SLHI’s distribution system is attached in Appendix C.

MAP OF DISTRIBUTION SERVICE TERRITORY:

The outlined area represents the Municipality of Sioux Lookout as well as SLHI's service territory.

APPENDIX B

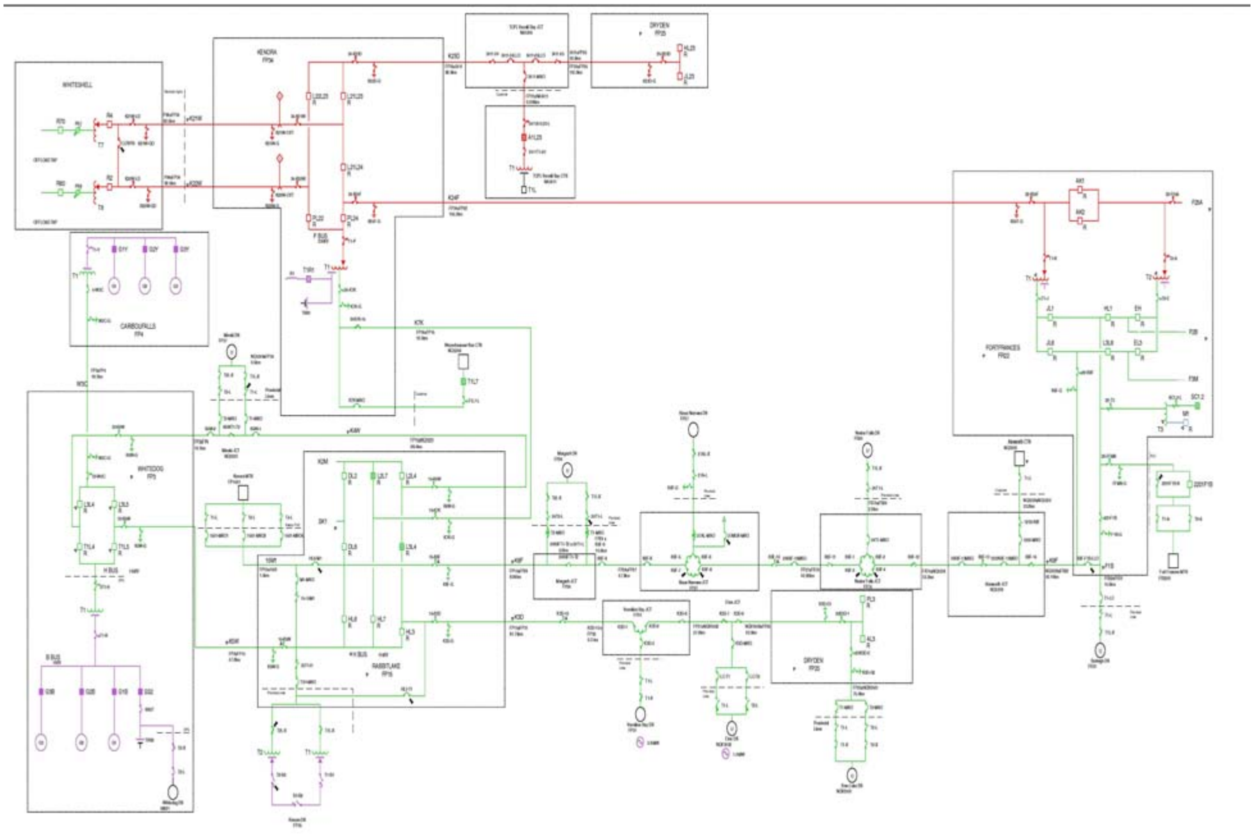
MAP OF DISTRIBUTION SERVICE TERRITORY



Sioux Lookout Hydro Inc.
EB-2012-0165
Exhibit 1
Tab 1
Schedule 9
Appendix C
Filed: February 22, 2013

APPENDIX C

MAP OF DISTRIBUTION SYSTEM



LIST OF NEIGHBOURING UTILITIES:

SLHI has one adjacent distributor which is Hydro One.

EXPLANATION OF HOST AND EMBEDDED UTILITIES:

SLHI is not a host utility and there are no embedded utilities in SLHI's distribution service territory. SLHI itself is embedded within Hydro One.

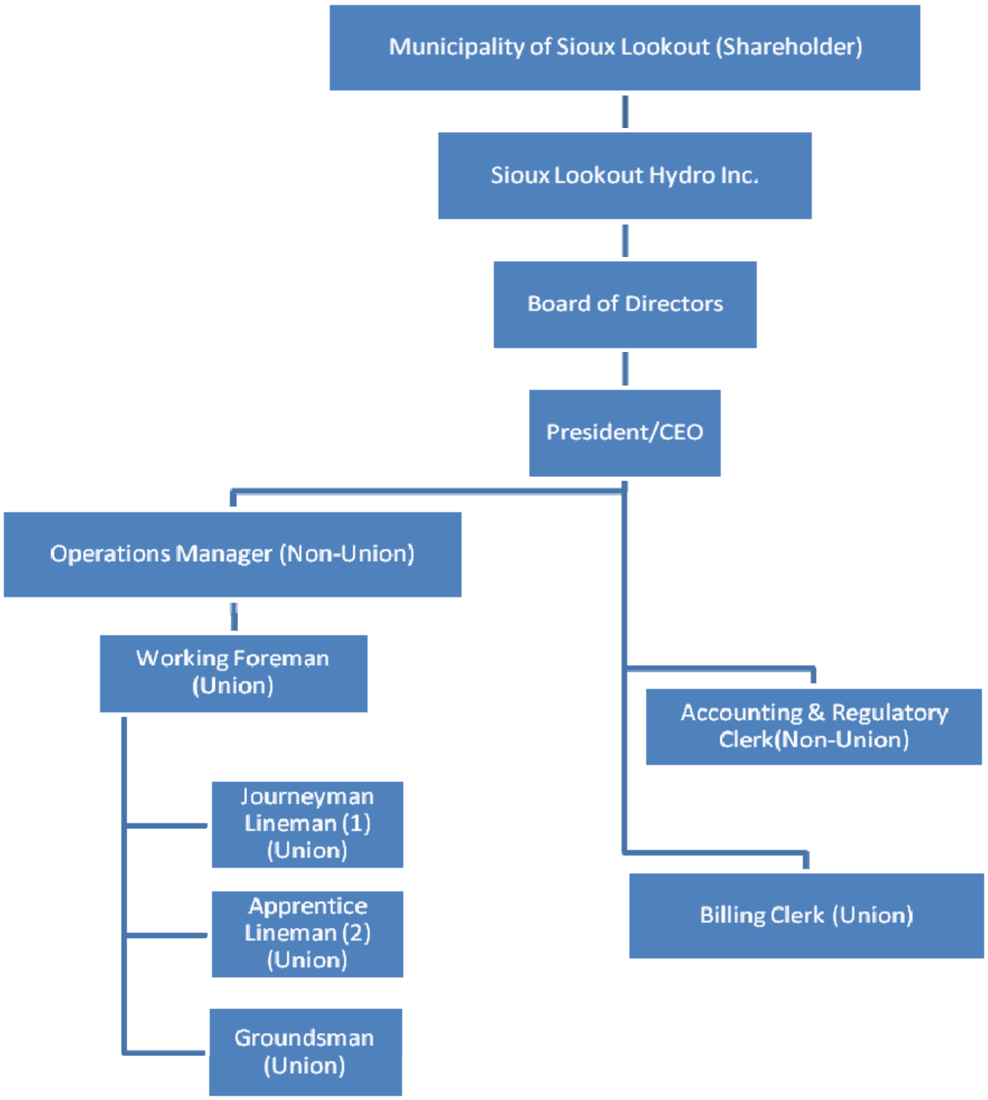
UTILITY ORGANIZATIONAL STRUCTURE:

SLHI is 100% owned by the Municipality of Sioux Lookout. A chart illustrating SLHI's organizational structure is provided at Exhibit 1, Tab 1, Schedule 13.

CORPORATE ENTITIES RELATIONSHIP CHART:

SLHI does not have any affiliate companies. SLHI's organizational structure is presented on the next page.

ORGANIZATIONAL STRUCTURE



PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to SLHI's corporate and operational structures are planned at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

Directive from 2008 Cost of Service Application (EB-2007-0785):

The Board prescribed a phase-in period to adjust its revenue-to-cost rates, moving the Street Lighting from their 2008 positions to the bottom of the Board's target ranges in equal increments over three (3) years. SLHI has complied with this directive and as of its 2010 IRM application (EB-2009-0249), Street Lighting Revenue-to-Cost Ratios have been moved to 70%.

Directive from 2009 IRM Application (EB:2008-0212)

SLHI has no outstanding directives from the above application.

Directive from 2010 IRM Application (EB-2009-0249)

The Board directed SLHI that, "*beginning July 1, 2010, Sioux Lookout shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits (ITCs)), the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of Sioux lookout's next cost of service rate order. 50% of the confirmed balances in the account shall be returnable to ratepayers.*"

SLHI has complied with the above directive. The details of the balance to be returned to ratepayers is found in Exhibit 9, Tab 2, Schedule 1.

Directive from 2011 IRM Application (EB-2010-0114)

SLHI has no outstanding directives from the above application.

Directive from 2012 IRM Application (EB-2011-0102)

SLHI has no outstanding directives from the above application.

Directive from 2012 Smart Meter Cost Recovery Application (EB-2012-0245)

The Board authorized SLHI to continue to use sub-account Stranded Meter Costs of Account 1555 to record and track remaining costs of the stranded conventional meters replaced by Smart Meters. The Board directed the balance to be brought forward for disposition in SLHI’s next cost of service application.

SLHI has requested disposition of the balance in Account 1555 – Sub-account Stranded Meter Costs in Exhibit 9, Tab 3, Schedule 1.

COMPANY POLICIES AND REGULATIONS/SERVICE CHARGES

SLHI's current version of its Conditions of Service is publicly available on the utility's website at www.siouxlookouthydro.com. This document is currently in the midst of being updated to provide more detail and clarity on certain matters, and once completed, will be posted on the website for public review and comments. As per the DSC Section 2.4.8, SLHI will provide the Board with a copy of the new Conditions of Service once they are implemented. A copy of the revised document shall include a cover letter that outlines the changes from the prior document as well as a summary of any public comments on the changes. The rates and charges in the document will be updated at that time, along with construction development fees. SLHI is not requesting any changes to the list of specific service charges.

PRELIMINARY LIST OF WITNESSES:

While SLHI requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary SLHI will provide a list of potential witnesses as required.

SUMMARY OF THE APPLICATION:

Preamble

SLHI has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Current rates will result in actual Return on Equity in 2012 and 2013 below levels currently approved by the OEB. The increased rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
2) Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance.
3) Maintain current staffing requirements, including training and preparing for succession planning.
4) To provide a reasonable rate of return to the Shareholder.

SLHI's Mission Statement is:

Sioux Lookout Hydro Inc. is committed to:

- Ensure that health and safety to employees and the Public is a priority,
- supply safe and reliable electricity to residents and businesses in the Municipality of Sioux Lookout
- provide superior customer service
- provide value to our Shareholder, the Municipality of Sioux Lookout.

SLHI's priorities are defined in its Corporate Goals:

Provide a safe and reliable electricity distribution system with capacity to meet the expectations of our customers and support local economic growth.

Promote and practice excellence in safety.

Establish the lowest retail rates possible without compromising the financial integrity of the Corporation in compliance to our Shareholder's direction and Corporate Strategic Plan.

Purpose and Need

SLHI's requested revenue requirement for 2013 in the amount of $2,091,430 includes the recovery of its costs to provide distribution services, its permitted Return on Equity ["ROE"] and the funds necessary to service its debt.

When forecasted energy and demand levels for 2013 are considered, SLHI estimates that its present rates will produce a deficiency in gross distribution revenue of $173,089 for the 2013 Test Year.

Therefore, SLHI seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Schedule 6 to this Application.

The information presented in this Application represents SLHI's forecasted results for its 2013 Test Year. SLHI is also presenting the forecasted results for 2012 Bridge Year and audited financial information for fiscal 2008, 2009, 2010 and 2011.

Timing

The financial information supporting the Test Year for this Application will be SLHI's fiscal year ending December 31, 2013 (the "2013 Test Year"). However, SLHI is requesting rates effective May 1, 2013, continuing through April 30, 2014. The Applicant requests that the OEB makes its rate order by May 13, 2013 in order to achieve this implementation date.

Customer Impact

In preparing this application, SLHI has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, SLHI notes that only the General Service 50 to 4999 kW class falls outside the applicable threshold defined by the Board in the March 31, 2012 Report of the Board on Review of Electricity Distribution Cost Allocation Policy (EB-2011-0219). In this application the General Service 50 to 4,999 kW class has been brought within the Board's threshold with minimal impact to other classes.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised low voltage rates, revised retail transmission rates, revised loss factors, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out in Table 1.1 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8, Appendix 8-B.

1.1: Bill Impact – Residential and General Service < 50 kW

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	$ 28.5200	1	$ 28.52	$ 4.26	17.56%
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	$ -	$ 2.8300	1	$ 2.83	$ 2.83	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0104	800	$ 8.32	$ 0.0122	800	$ 9.76	$ 1.44	17.31%
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			$ 46.49	**$ 4.48**	**10.66%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0035	800	-$ 2.80	-$ 0.0028	800	-$ 2.24	$ 0.56	-20.00%
			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**			**$ 44.25**	**$ 5.04**	**12.85%**
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**			**$ 51.22**	**$ 6.22**	**13.83%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	851	$ 4.43	$ 0.0052	872	$ 4.53	$ 0.11	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	851	$ 0.94	$ 0.0011	872	$ 0.96	$ 0.02	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	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**			**$ 127.58**	**$ 8.01**	**6.70%**
HST		13%		$ 15.54	13%		$ 16.59	$ 1.04	6.70%
Total Bill (including HST)				$ 135.12			$ 144.16	$ 9.05	6.70%
Ontario Clean Energy Benefit [1]				-$ 13.51			-$ 14.42	-$ 0.91	6.74%
Total Bill on RPP (including OCEB)				**$ 121.61**			**$ 129.74**	**$ 8.14**	**6.69%**
Total Bill on TOU (before Taxes)				**$ 124.15**			**$ 132.27**	**$ 8.12**	**6.54%**
HST		13%		$ 16.14	13%		$ 17.19	$ 1.06	6.54%
Total Bill (including HST)				$ 140.29			$ 149.46	$ 9.17	6.54%
Ontario Clean Energy Benefit [1]				-$ 14.03			-$ 14.95	-$ 0.92	6.56%
Total Bill on TOU (including OCEB)				**$ 126.26**			**$ 134.51**	**$ 8.25**	**6.53%**

Loss Factor (%) 6.42% (current) 8.97% (proposed)

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 ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 43.1100	1	$ 43.11	$ 44.9800	1	$ 44.98	$ 1.87	4.34%
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	$ -	$ 2.6300	1	$ 2.63	$ 2.63	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0082	2000	$ 16.40	$ 0.0086	2000	$ 17.20	$ 0.80	4.88%
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			$ 74.10	**$ 0.92**	**1.26%**
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**			**$ 67.90**	**$ 0.32**	**0.47%**
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**			**$ 83.37**	**$ 2.81**	**3.49%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2128	$ 11.07	$ 0.0052	2179	$ 11.33	$ 0.27	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2128	$ 2.34	$ 0.0011	2179	$ 2.40	$ 0.06	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	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**			**$ 289.22**	**$ 7.93**	**2.82%**
HST		13%		$ 36.57	13%		$ 37.60	$ 1.03	2.82%
Total Bill (including HST)				$ 317.86			$ 326.82	$ 8.96	2.82%
Ontario Clean Energy Benefit [1]				-$ 31.79			-$ 32.68	-$ 0.89	2.80%
Total Bill on RPP (including OCEB)				**$ 286.07**			**$ 294.14**	**$ 8.07**	**2.82%**
Total Bill on TOU (before Taxes)				**$ 278.07**			**$ 285.61**	**$ 7.54**	**2.71%**
HST		13%		$ 36.15	13%		$ 37.13	$ 0.98	2.71%
Total Bill (including HST)				$ 314.22			$ 322.74	$ 8.52	2.71%
Ontario Clean Energy Benefit [1]				-$ 31.42			-$ 32.27	-$ 0.85	2.71%
Total Bill on TOU (including OCEB)				**$ 282.80**			**$ 290.47**	**$ 7.67**	**2.71%**

Loss Factor (%)	6.42%	8.97%

Transition to Modified International Financial Reporting Standards (MIFRS)

Historically SLHI has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. As stated throughout this application, given the recent announcement by the Canadian Accounting Standards Board (AcSB) " In anticipation of future activities of the International Accounting Standards Board, the Canadian Accounting Standards Board decided at its September 2012 meeting to extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities to 1 January 2014", SLHI will be deferring the changeover date to International Financial Reporting Standards (IFRS) to January 1, 2014. As such, this application has been prepared using what has been termed "modified CGAAP" (MCGAAP). The actuals for 2008 through to 2011 have been prepared using CGAAP as historically done and the Bridge Year 2012 has been prepared using CGAAP as well; however, updating the capitalization and depreciation policy to align with IFRS. SLHI's rationale for preparing this application in this manner is given the recent change by the AcSB, SLHI's changeover date is now January 1, 2014 and the transition date is January 1, 2013. To allow transparent and useful comparisons to historical expenses, the expenses approved in SLHI's 2008 Cost of Service application, and to clearly illustrate the impact of the updating of SLHI's capitalization and depreciation policy, the forecasted 2012 Bridge Year has been prepared using both SLHI's historical capitalization and depreciation policy and the updated policies. The change in SLHI's capitalization and depreciation policies has impacted the calculation of the cost of self-constructed assets, depreciation rates, and operating expenses. These changes have impacted the 2013 rate base and the 2013 distribution revenue requirement. SLHI has provided detailed explanations of these changes in the applicable section of the application.

Smart Meters:

2013 smart meter costs are included the 2013 rate base and revenue requirement. SLHI submitted a stand alone application to dispose of their Smart Meter Variance accounts 1555 and 1556. The Board approved the application on August 23, 2012. SLHI is also requesting the recovery of stranded meter amounts as outlined in Exhibit 9 of this Application.

Capital Structure

SLHI is requesting the continuation of its current deemed capital structure of 40% Equity, 4% Short Term Debt, 56% Long Term Debt.

Return on Equity

SLHI has assumed a return on equity of 9.12% consistent with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. SLHI understands the Board will be finalizing the cost of capital parameters for 2013 rates based on January 2013 market interest rate information, and that adjustments to the Application may be required as a result.

Capital Expenditures

SLHI continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. Given that SLHI's load has been relatively flat in the last few years, the increase in demand comes mainly from distribution system replacements/upgrades needed in existing areas. SLHI's core business is the safe, reliable delivery of electricity to the residents and businesses of Sioux Lookout. SLHI's recent development of their asset management plan provides the framework to move forward to ensure that core business objectives are realized. SLHI's capital expenditures reflect that the distribution system was largely rebuilt in the 1980's and therefore there is currently a low need for infrastructure replacement.

BUDGET OVERVIEW:

SLHI compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2012 Bridge Year and the 2013 Test Year.

Revenue Forecast

SLHI's energy sales and revenue forecast model were updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2012 and 2013. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 1 and considers such factors as average weather conditions and economic conditions in the area serviced by SLHI.

Operating Maintenance and Administration ("OM&A") Expense Forecast

The OM&A expenses for the 2012 Bridge Year and the 2013 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The capital budget forecast 2012 and 2013 is influenced by, among other factors, the highest priority capital requirements and SLHI's capacity to finance capital projects. Indirect costs are allocated to direct costs in the capital budget. All proposed capital projects are assessed within the framework of their capital budget priority and are outlined in Exhibit 2, Tab 3.

The development of the Asset Management Plan, which was completed in 2012 identified assets which were in need of repair or replacement. The process included inspecting all poles in the distribution system and assessing the condition, which is one of the drivers of the capital budget.

Also, in order to improve reliability SLHI budgets for voltage upgrades as outlined in Exhibit 2, Tab 3.

CHANGES IN METHODOLOGY

SLHI is not requesting any changes in methodology in the current proceeding.

CALCULATION OF REVENUE DEFICIENCY:

SLHI has provided detailed calculations supporting its 2013 revenue deficiency. SLHI's net revenue deficiency is $146,260 and when grossed up for PILs, SLHI's revenue deficiency is $173,089. Table 1.2-2 on the following page provides the revenue deficiency calculations for the 2013 Test Year at Existing 2012 Board-approved rates and the 2013 Test Year Revenue Requirement. For informational purposes, a schedule of the most recent Board Approved revenue requirement is found below in Table 1.2-1.

Table 1.2-1: Most recent Board-approved Revenue Requirement

EB-2007-0745 Rate Year 2008	
OM&A Expenses	$1,128,526
Amortization/Depreciation	$318,273
PILs (with gross-up)	$55,473
Return	
Deemed Interest Expense	$198,042
Return on Equity	$248,467
Distribution Revenue Requirement before Revenues	**$1,948,781**
Distribution Revenue	$1,774,640
Other Revenue	$174,140
Total Revenue	**$1,948,780**
Difference (Total Revenue less Distribution Revenue Requirement before Revenues)	$1

Table 1.2-2: Calculation of Revenue Deficiency

Description	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue		
Revenue Deficiency		**173,089**
Distribution Revenue	1,789,316	1,789,316
Other Operating Revenue (Net)	129,025	129,025
Total Revenue	**1,918,341**	**2,091,430**
Costs and Expenses		
Administrative & General, Billing & Collecting	724,425	724,425
Operation & Maintenance	825,008	825,008
Depreciation & Amortization	180,404	180,404
Property Taxes	4,986	4,986
Deemed Interest	122,772	122,772
Total Costs and Expenses	**1,857,595**	**1,857,595**
Utility Income Before Income Taxes	**60,746**	**233,834**
Income Taxes:		
Corporate Income Taxes	-15,763	11,066
Total Income Taxes	**-15,763**	**11,066**
Utility Net Income	**76,509**	**222,769**
Income Tax Expense Calculation:		
Accounting Income	60,746	233,834
Tax Adjustments to Accounting Income	-162,444	-162,444
Taxable Income	**-101,698**	**71,390**
Income Tax Expense	**-15,763**	11,066
Tax Rate Refecting Tax Credits	15.50%	15.50%
Actual Return on Rate Base:		
Rate Base	6,106,606	6,106,606
Interest Expense	122,772	122,772
Net Income	76,509	222,769
Total Actual Return on Rate Base	**199,281**	**345,541**
Actual Return on Rate Base	3.26%	5.66%
Required Return on Rate Base:		
Rate Base	6,106,606	6,106,606
Return Rates:		
Return on Debt (Weighted)	3.35%	3.35%
Return on Equity	9.12%	9.12%
Deemed Interest Expense	122,772	122,772
Return On Equity	222,769	222,769
Total Return	**345,541**	**345,541**
Expected Return on Rate Base	5.66%	5.66%
Revenue Deficiency After Tax	**146,260**	**-0**
Revenue Deficiency Before Tax	**173,089**	**-0**

CAUSES OF REVENUE DEFICIENCY:

SLHI's net revenue deficiency is calculated as $146,260 and when grossed up for PILs, the revenue deficiency is $173,089. SLHI's calculation of its 2013 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 4 and Exhibit 6, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- Increases in OM&A costs since SLHI's last cost of service in 2008. For the 2013 Test Year SLHI is forecasting OM&A expenses increasing at a compound annual growth rate of 5.6% per year since 2008 Board Approved, under CGAAP (The compound annual growth rate is 5.2% from 2008 actual). The transition from CGAAP to MCGAAP will increase operating expenses by an additional $39,127. There is also an additional $59,167 in smart meter related OM&A. SLHI has provided a detailed explanation of changes in operating expenses in Exhibit 4.

FINANCIAL STATEMENTS – 2008, 2009, 2010 and 2011:

SLHI's Audited Financial Statements accompany this Schedule as Appendix D.

APPENDIX D

COPIES OF SIOUX LOOKOUT HYDRO INC. AUDITED FINANCIAL STATEMENTS

FOR 2008, 2009, 2010 and 2011

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2008

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2008

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Notes to Financial Statements 11

BDO Dunwoody LLP
Chartered Accountants
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Dryden Ontario Canada P8N 3G3
Telephone: (807) 223-5321
Telefax: (807) 223-2978

Auditors' Report

To the Shareholder of
Sioux Lookout Hydro Inc.

We have audited the balance sheet of Sioux Lookout Hydro Inc. as at December 31, 2008 and the statements of retained earnings, operations and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2008 and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO Dunwoody LLP

Chartered Accountants, Licensed Public Accountants

Dryden, Ontario
March 11, 2009

Sioux Lookout Hydro Inc.
Balance Sheet

December 31		2008		2007
Assets				
Current				
Cash and bank	$	**729,706**	$	1,136,557
Accounts receivable		**730,009**		712,778
Unbilled revenue		**1,049,432**		933,079
Inventory (Note 1)		**75,214**		64,014
Prepaid expenses		**40,922**		25,063
Taxes receivable		**2,722**		4,859
		2,628,005		2,876,350
Regulatory assets (Note 3)		**72,953**		-
Capital assets (Note 4)		**4,635,240**		4,651,755
Goodwill		**300,979**		300,979
	$	**7,637,177**	$	7,829,084
Liabilities and Shareholder's Equity				
Current				
Bank indebtedness (Note 5)	$	**2,502,989**	$	2,688,989
Accounts payable and accrued liabilities		**1,728,047**		1,534,830
Employee benefits payable (Note 6)		**109,456**		95,254
Customer deposits		**116,955**		101,054
Due to related parties (Note 2)		**310,974**		241,663
		4,768,421		4,661,790
Regulatory liabilities (Note 3)		**-**		208,559
		4,768,421		4,870,349
Shareholder's equity				
Share capital (Note 8)		**2,789,823**		2,789,823
Retained earnings		**78,933**		168,912
		2,868,756		2,958,735
	$	**7,637,177**	$	7,829,084

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Retained Earnings

For the year ended December 31		2008		2007
Retained earnings, beginning of year	$	**168,912**	$	252,695
Net income for the year		**95,021**		46,217
		263,933		298,912
Dividends		**(185,000)**		(130,000)
Retained earnings, end of year	$	**78,933**	$	168,912

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Operations

For the year ended December 31		2008			2007	
Revenue						
Sale of energy						
Residential and general	$	**6,898,509**	**97.6 %**	$	8,468,038	101.4 %
Street lighting		**50,671**	**0.7 %**		51,583	0.6 %
Unbilled revenue adjustment		**116,353**	**1.6 %**		(170,678)	(2.0)%
		7,065,533	**100 %**		8,348,943	100 %
Cost of bulk power purchased		**5,560,389**	**78.7 %**		6,917,995	82.9 %
Gross margin on energy sold		**1,505,144**	**21.3 %**		1,430,948	17.1 %
Other operating revenue (Note 10)		**155,266**	**2.3 %**		177,889	2.1 %
		1,660,410	**23.5 %**		1,608,837	19.3 %
Expenditures						
Administration		**492,172**	**6.9 %**		589,553	7.1 %
Amortization		**255,118**	**3.6 %**		243,396	2.9 %
Interest and bank charges		**196,482**	**2.7 %**		199,701	2.4 %
Operation maintenance		**595,799**	**8.5 %**		501,429	6.0 %
		1,539,571	**21.7 %**		1,534,079	18.4 %
Income before payment in lieu of taxes		**120,839**	**1.8 %**		74,758	0.9 %
Payment in lieu of taxes						
Payment in lieu of taxes		**25,818**	**0.5 %**		28,541	0.3 %
Net income for the year	$	**95,021**	**1.3 %**	$	46,217	0.6 %

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Cash Flows

For the year ended December 31		2008		2007
Cash provided by (used in)				
Operating activities				
Net income for the year	$	**95,021**	$	46,217
Items not involving cash				
Amortization of capital assets (Note 13)		**325,447**		308,160
Loss on disposal of capital assets		**2,001**		6,120
		422,469		360,497
Changes in non-cash working capital balances				
Accounts receivable		**(17,231)**		217,675
Unbilled revenue		**(116,353)**		170,678
Due to/from related parties		**69,309**		(132,675)
Inventory		**(11,200)**		1,922
Prepaid expenses		**(15,859)**		21,616
Accounts payable and accrued liabilities		**193,217**		(62,850)
Employee benefits payable		**14,205**		(7,045)
Taxes receivable		**2,137**		(3,393)
Customer deposits		**15,901**		8,335
		556,595		574,760
Investing activities				
Purchase of capital assets		**(312,707)**		(259,189)
Increase (decrease) in regulatory assets (liabilities)		**(281,512)**		(73,007)
Proceeds on sale of capital assets		**1,773**		-
Reduction in capital contributed		**-**		(1,226,489)
		(592,446)		(1,558,685)
Financing activities				
Increase (decrease) in bank indebtedness		**(186,000)**		1,067,322
Dividends		**(185,000)**		(130,000)
		(371,000)		937,322
Decrease in cash during the year		**(406,851)**		(46,603)
Cash and bank, beginning of year		**1,136,557**		1,183,160
Cash and bank, end of year	$	**729,706**	$	1,136,557

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2008

Nature of Business

The company is incorporated under the laws of Ontario and is licenced by the Ontario Energy Board (OEB) as an electricity distributor.

Inventory

Inventory is stated at the lower of cost and net realizable value. Cost is generally determined on the average cost basis.

Capital Assets

Capital assets are recorded at cost less accumulated amortization. Amortization is provided on a straight line basis over the assets estimated useful life.

Buildings	- 25	years
Distribution system - overhead	- 25	years
Distribution system - underground	- 25 and 35	years
Distribution transformers	- 25 and 35	years
Distribution meters	- 25 and 35	years
Other equipment - various	- from 4 to 10	years

Goodwill

Goodwill being the excess of cost over assigned values of net assets acquired, is stated at cost. No amortization is provided for goodwill. The value of goodwill is regularly evaluated by reviewing the returns of the related business, taking into account the risk associated with the investment. Any impairment in the value of the goodwill is written off against earnings.

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills.

Revenue Recognition

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

The amounts billed to customers for distribution services is according to rates, both fixed and by volume of power, as approved by the Ontario Energy Board.

Pole rental revenues which is included in other operating revenue is according to rates per pole as established by the Ontario Energy Board.

Late payment charges and interest income is recognized as revenue when earned.

December 31, 2008

Capital Contributions and Grants

Capital contributions are set up as a capital asset contra account, contributions and grants. This account is amortized on the same basis as the related capital assets.

Payment in Lieu of Taxes

The company accounts for payment in lieu of taxes using the tax payable method. Under this method, the company only reports as an expense the cost of current payment in lieu of taxes for the year, determined in accordance with the rules established by the taxation authorities. Future payment in lieu of taxes have not been reported as it is the opinion of management that these taxes will be recovered from customers in the future.

Use of Estimates

The preparation of financial statements in accordance with accounting policies established for electric utilities in the Province of Ontario requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

The company utilizes various financial instruments. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of the financial instruments approximate their carrying values, unless otherwise noted.

All transactions related to financial instruments are recorded on a trade date basis.

The company classifies its financial instruments into one of the following categories based on the purpose for which the asset was acquired. The company's accounting policy for each category is as follows:

Held-for-Trading

This category is comprised of cash and bank. They are carried in the balance sheet at fair value with changes in fair value recognized in the statement of operations. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Loans and Receivables

These assets are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date or dates or on demand. They arise principally through the provision of goods and services to customers (accounts receivable and unbilled revenue), but also incorporate other types of contractual monetary assets. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest method, less any provision for impairment. Transaction costs related to loans and receivables are expensed as incurred.

Other Financial Liabilities

Other financial liabilities includes all financial liabilities other than those classifed as held-for-trading and comprise accounts payable and accrued liabilities, due to related parties, and bank borrowings. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are expensed as incurred.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

a) International Financial Reporting Standards

The AcSB plans to converge Canadian GAAP with International Financial Reporting Standards ("IFRS") over a transition period expected to end in 2011. The impact of the transition to IFRS on the company's financial statements has yet to be determined.

b) General Standards on Financial Statement Presentation

CICA Handbook Section 1400, General Standards on Financial Statement Presentation, has been amended to include requirements to assess and disclose an entity's ability to continue as a going concern. The changes are effective for interim and annual financial statements beginning on or after January 1, 2008. The company does not expect the adoption of these changes to have a material impact on its financial statements.

c) Income Taxes

CICA Handbook Section 3465, Income Taxes, was amended to require rate regulated enterprises to recognize future income taxes, liabilities and assets, as well as regulatory assets or liability for the amount of future income taxes to be expected to be included in future rates and recovered from or returned to future customers in the financial statements. The changes are effective for interim and annual financial statements beginning on or after January 1, 2009. The company does not expect the adoption of these changes to have a material impact on its financial statements as disclosed in Note 7.

1. Inventory

	2008	2007
Balance, beginning of year	$ **64,014**	$ 65,936
Purchases	**46,608**	94,595
Transfer to capital assets	**(35,408)**	(96,517)
Balance, end of year	$ **75,214**	$ 64,014

2. Due to Related Parties

At the end of the year the amounts due to related parties are as follows:

	2008	2007
Due to Shareholder:		
Corporation of the Municipality of Sioux Lookout	$ **310,974**	$ 241,663

These balances are unsecured, interest free, payable on demand and have arisen from the transfer of assets, dividends declared and provision of services referred to below.

The Corporation provides billing services to Corporation of the Municipality of Sioux Lookout for sewer and water. At year end, the uncollected bills from customers was $125,974 (2007 - $111,633). As well there was a dividend declared and payable of $185,000 (2007 - $130,000). During the year the company billed electricity and services to the shareholder in the amount of $658,767 (2007 - $667,479).

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

For due to related parties it is not practicable within the constraints of timeliness or cost to determine the fair value with sufficient reliability because the instruments are not traded in an organized financial market and the timing of the cash flows cannot be determined.

December 31, 2008

3. Regulatory Assets (Liabilities)

Under Bill 210, certain costs and variance account balances are deemed to be "regulatory assets (liabilities)" in accordance with the OEB Accounting Procedures Handbook. These assets are to be reflected on the Corporation's balance sheet. The OEB has granted the Corporation permission to recover the regulatory assets when establishing its distribution rates. The manner and timing of the regulatory assets (iabilities) has not been determined by the OEB.

	2008	2007
Retail settlement variances	$ 15,973	$ 13,415
Wholesale market service variances	(7,798)	(8,442)
Network charges variances	(135,040)	(66,441)
Connection charges variances	(449,692)	(304,056)
Power charges variances	647,416	294,240
Approved rate adjustment	280,953	-
Rate rider variance	5,255	(8,593)
Transitional costs	-	6,320
Assets recovered through rates	(284,114)	415,188
Extraordinary events variance	-	(550,190)
	$ 72,953	$ (208,559)

4. Capital Assets

	2008		2007	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Buildings	$ 91,864	$ 29,998	$ 91,864	$ 26,324
Distribution system-overhead	4,016,093	1,135,936	3,858,720	975,292
Distribution system - underground	933,687	252,242	872,068	214,895
Distribution transformers	1,470,153	402,232	1,336,479	343,426
Distribution meters	320,348	87,073	318,716	73,674
Other equipment - various	671,770	470,078	615,820	420,273
Contributions and grants	(608,208)	(113,580)	(524,528)	(89,251)
Construction in progress	3,512	-	47,249	-
	$ 6,899,219	$ 2,263,979	$ 6,616,388	$ 1,964,633
Net book value		$ 4,635,240		$ 4,651,755

December 31, 2008

5. Bank Indebtedness

	2008	2007
Demand instalment loan, repayable at $15,500 per month plus interest at prime, secured by a general security agreement covering all assets; due 2022	**$ 2,502,989**	$ 2,688,989

The bank operating loan is due on demand and bears interest at the bank's prime rate, calculated and payable monthly. It is secured by a general security agreement covering all assets and is guaranteed by Corporation of the Municipality of Sioux Lookout.

The company has an unused operating line of credit of $175,000 with terms of due on demand and bears interest at the bank's prime rate calculated and payable monthly.

The agreement governing the demand instalment loan facility contains certain covenants regarding (i) debt servicing ratios, (ii) negative pledge where no lien can be assigned against assets, and (iii) the bank must permit any material change to the company.

The company was in compliance with all covenants as at December 31, 2008.

6. Employee Benefits Payable

	2008	2007
Vacation pay	**$ 22,098**	$ 10,467
Vested sick leave	**39,811**	34,621
Banked overtime	**2,900**	5,182
Post employment benefits	**44,647**	44,984
	$ 109,456	$ 95,254

The post employment benefits is estimated based on the premiums paid to employees from date eligible to retire, until age 65. The estimate assumes an inflation rate of 3.46% and a discount rate of 4%.

7. Payment in Lieu of Taxes

Future payments in lieu of taxes have not been recorded in the accounts as they are expected to be reflected through future distribution revenues. As at December 31, 2008 a future income tax asset of $76,687 (2006 - $64,030) has not been recorded on the balance sheet. A future payment in lieu of taxes (recovery) of ($12,656) (2007 - $6,568) has not been reflected in the income tax provision for the year ended December 31, 2008.

December 31, 2008

8. Share Capital

The authorized class A preference share capital of the company is an unlimited number of non-voting shares, with a stated value equal to the consideration received on issue, redeemable and retractable at $1,000 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class B preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $100 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class C preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class D preference share capital of the company is an unlimited number of voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized common share capital of the company is an unlimited number of shares.

The issued share capital is as follows:

		2008	2007
100	Common shares	**$ 2,789,823**	$ 2,789,823

9. Financial Income and Expense

	2008	2007
Interest on assets held-for-trading	**$ 33,443**	$ 54,111
Interest expense on financial liabilities measured at amortized cost	**135,717**	189,108
Interest expense on financial assets measured at fair value	**60,765**	54,288
	196,482	243,396
Net finance costs	**$ (163,039)**	$ (189,285)

10. Other Operating Revenue

		2008		2007
Late payment charges	$	**40,428**	$	52,228
Interest income		**33,443**		54,111
Pole rentals		**38,630**		32,574
Change in occupancy charges		**19,410**		20,490
Sentinel light rental		**9,691**		9,164
Sundry		**13,664**		9,322
	$	**155,266**	$	177,889

11. Pension Agreement

The company makes contributions to the Ontario Municipal Employers Retirement Fund (OMERS), which is a multi-employer plan, on behalf of seven members of its staff. The plan is a deferred benefit plan which specifies the amount of the retirement benefit to be received by the employee based on the length of service and rate of pay.

During the year ended December 31, 2008 the Board contributed $36,012 (2007 - $30,397) to the plan. As this is a multi-employer pension plan, these contributions are the Board's pension benefit expenses. No pension liability for this type of plan is included in the Board's financial statements.

12. Supplementary Cash Flow Information

		2008		2007
Interest paid	$	**203,763**	$	194,082
Payment in lieu of taxes paid		**23,681**		28,610
	$	**227,444**	$	222,692

13. Amortization of Capital Assets

		2008		2007
Amortization of building and distribution equipment	$	**274,038**	$	259,849
Amortization of office equipment		**3,080**		2,341
Amortization of contributions and grants		**(24,328)**		(20,981)
		252,790		241,209
Amortization of other capital assets included in relevant expense categories				
Rolling stock		**54,308**		50,096
Operations and maintenance		**16,021**		14,668
Sentinel lights		**2,328**		2,187
	$	**325,447**	$	308,160

14. Commitments

The company has also entered into an operating lease for its equipment (Altec Aerial Device). The equipment is leased at $3,176 per month under a lease expiring in 2013.

The minimum annual lease payments for the next three years are as follows:

2009	$	38,112
2010		38,112
2011		38,112

15. Fair Value of Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable and accrued liabilities approximate their carrying amounts because of the short-term maturity of these instruments.

The fair value of the demand instalment loan approximates its carrying value since the interest rate fluctuates with prime and the rates used to renew this debt are prime. The discounted cash flows would equal the amount reported on the financial statement.

The fair value of the due to related parties amount has not not been determined as disclosed in Note 2.

16. Other Comprehensive Income

Other comprehensive income includes, in particular, unrealized gains and losses on available-for-sale assets and the change in the effective portion of a cash flow hedge transaction. The company had no other comprehensive income for the year.

17. Financial Instrument Risk Exposure and Management

The Board has overall responsibility for the determination of the company's risk management objectives and policies while retaining ultimate responsibility for them. It has delegated the authority for designing and operating processes that ensure the effectiveness of the objectives and policies to the company's finance function. The Board receives quarterly financial reports from the manager through which it reviews the effectiveness of the processes put in place and the results of operations.

Credit Risk

The company has a policy it follows to ensure that the accounts receivables are collected on a timely basis. When a customer account goes into arrears Thunder Bay Hydro Inc. calls the customer in an effort to secure payment. In the event that the calls fail, Sioux Lookout Hydro Inc. will follow up with a letter that explains to the customer the ramifications of not paying their account. Once several days pass the services provided to the customer will be cut off. This process is followed unless the Board directs management to exclude certain customers groups from having their services cut off.

If a customer leaves their residence and the above collection process is not successful, Sioux Lookout Hydro Inc. will engage the services of a collection bureau to pursue these customer accounts. When an account is transfered to a collection bureau management sets these accounts up as doubtful accounts. At year end the allowance for doubtful accounts balance was $58,703 (2007 - $68,538). When all avenues to collect outstanding receivables have been exhausted management, with Board approval, will write off the receivables. During the year the company wrote off $36,991 of outstanding receivables (2007 - $ 60,209).

Sioux Lookout Hydro Inc. is in the normal course of operations, exposed to credit risk from having bank account balances over the amounts insured by the Canadian Deposit Insurance Corporation.

Liquidity Risk

The company's policy is to ensure that it will always have sufficient cash to allow it to meet its liabilities when they become due. Management reconciles its bank on a monthly basis and it funds temporary cash shortages through a line of credit with the bank.

December 31, 2008

17. Financial Instrument Risk Exposure and Management (continued)

The following table illustrates the contractual maturity analysis of the company's financial liabilities. It is prepared on a gross basis and assumes the bank demand loan is repaid according to the instalment schedule and prevailing interest rates (prime).

	2009	2010	2011	2012	2013	Thereafter	Total
Non-derivative financial instruments	$ 258,532	$ 252,952	$ 247,792	$ 241,792	$ 236,212	$ 1,774,080	$3,011,360

Market Risk

Market risk arises from the company's floating rate demand loan.

The annualized effect of a 1.0% decrease in the interest rate at the balance sheet date on the floating rate demand loan carried at that date would, all other variables held constant; have resulted in an increase in post-tax profit for the year of $24,000. A 1.0% increase in the interest rate would, on the same basis, have decreased post-tax profit by the same amount.

Capital Disclosures

Sioux Lookout Hydro Inc. manages its capital in a manner consistent with the risk characteristics of the assets it holds. All financing, including equity and debt are analyzed by management and approved by the board of directors.

The company's objectives when managing capital are:

a) to safeguard the company's ability to continue as a going concern and provide returns for shareholders;

b) to maintain a safe and reliable electricity distribution system.

The company is meeting its objective of managing capital through its detailed review and preparing short term and long term cash flow analysis to ensure an adequate amount of liquidity and monthly review of financial results.

There have been no changes in the company's approach to capital management from the previous years.

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2009

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2009

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Auditors' Report

To the Shareholder of
Sioux Lookout Hydro Inc.

We have audited the balance sheet of Sioux Lookout Hydro Inc. as at December 31, 2009 and the statements of retained earnings, operations and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2009 and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Dryden, Ontario
March 12, 2010

Sioux Lookout Hydro Inc.
Balance Sheet

December 31	2009	2008 (Restated)
Assets		
Current		
Cash and bank	$ **1,008,668**	$ 729,706
Accounts receivable	**536,652**	730,010
Unbilled revenue	**1,060,301**	1,049,432
Inventory (Note 1)	**52,707**	75,214
Prepaid expenses	**35,031**	40,922
	2,693,359	2,625,284
Regulatory assets (Note 3)	**633,617**	170,781
Capital assets (Note 4)	**4,575,160**	4,635,240
Goodwill	**-**	300,979
Future income tax assets	**113,196**	-
	$ **8,015,332**	$ 7,732,284
Liabilities and Shareholder's Equity		
Current		
Bank indebtedness (Note 5)	$ **3,052,492**	$ 2,502,989
Accounts payable and accrued liabilities	**1,359,672**	1,728,048
Employee benefits payable (Note 6)	**116,634**	109,456
Taxes payable	**65,898**	16,778
Customer deposits	**130,667**	116,955
Due to related parties (Note 2)	**412,092**	310,974
	5,137,455	4,785,200
Shareholder's equity		
Share capital (Note 7)	**2,789,823**	2,789,823
Retained earnings	**88,054**	157,261
	2,877,877	2,947,084
	$ **8,015,332**	$ 7,732,284

On behalf of the Board:

_______________________ Director

_______________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Retained Earnings

For the year ended December 31		2009		2008 (Restated)
Retained earnings, beginning of year	$	78,933	$	168,912
Correction of prior period error (Note 18)		78,328		69,148
Retained earnings, beginning of year, as restated		157,261		238,060
Net income for the year		93,107		104,201
Change in accounting policy (Note 17)		76,686		-
Dividends		(239,000)		(185,000)
Retained earnings, end of year	$	88,054	$	157,261

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Operations

For the year ended December 31	2009		2008 (Restated)	
Revenue				
Sale of energy				
Residential and general	**$ 5,150,127**	**97.9 %**	$ 6,898,509	97.7 %
Street lighting	**102,052**	**1.9 %**	50,671	0.7 %
Unbilled revenue adjustment	**10,869**	**0.2 %**	116,353	1.6 %
	5,263,048	**100 %**	7,065,533	100 %
Cost of bulk power purchased	**3,497,911**	**66.5 %**	5,560,389	78.7 %
Gross margin on energy sold	**1,765,137**	**33.5 %**	1,505,144	21.3 %
Other operating revenue (Note 9)	**138,002**	**2.7 %**	166,717	2.4 %
	1,903,139	**36.2 %**	1,671,861	23.7 %
Expenditures				
Administration	**513,786**	**9.7 %**	492,148	7.0 %
Amortization	**269,056**	**5.1 %**	255,118	3.6 %
Interest and bank charges	**125,768**	**2.5 %**	196,482	2.8 %
Operation maintenance	**564,734**	**10.8 %**	595,799	8.4 %
	1,473,344	**28.1 %**	1,539,547	21.8 %
Income before other item and payment in lieu of taxes	**429,795**	**8.2 %**	132,314	1.9 %
Other item				
Loss on impairment of goodwill (Note 15)	**(300,979)**	**(5.7)%**	-	- %
Income before payment in lieu of taxes	**128,816**	**7.5 %**	132,314	1.5 %
Payment in lieu of taxes				
Payment in lieu of taxes	**72,218**	**1.4 %**	28,113	0.4 %
Future payment in lieu recoverable	**(36,509)**	**(0.7)%**	-	- %
	35,709	**0.7 %**	28,113	0.4 %
Net income for the year	**$ 93,107**	**1.8 %**	$ 104,201	1.5 %

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Cash Flows

For the year ended December 31	2009	2008 (Restated)
Cash provided by (used in)		
Operating activities		
Net income for the year	$ 93,107	$ 104,201
Items not involving cash		
Amortization of capital assets (Note 12)	333,914	325,447
Future income taxes (recovery)	(36,509)	-
Loss on disposal of capital assets	16,347	2,001
Loss on impairment of goodwill	300,979	-
	707,838	431,649
Changes in non-cash working capital balances		
Accounts receivable	193,357	(17,231)
Unbilled revenue	(10,869)	(116,353)
Due to related parties	101,116	69,309
Inventory	22,507	(11,200)
Prepaid expenses	5,896	(15,859)
Accounts payable and accrued liabilities	(368,379)	193,217
Employee benefits payable	7,178	14,205
Taxes receivable	49,120	4,432
Customer deposits	13,712	15,901
	721,476	568,070
Investing activities		
Purchase of capital assets	(290,548)	(312,707)
Increase in regulatory assets (liabilities)	(462,836)	(292,987)
Proceeds on sale of capital assets	367	1,773
	(753,017)	(603,921)
Financing activities		
Increase (decrease) in bank indebtedness	549,503	(186,000)
Dividends	(239,000)	(185,000)
	310,503	(371,000)
Increase (decrease) in cash during the year	278,962	(406,851)
Cash and bank, beginning of year	729,706	1,136,557
Cash and bank, end of year	$ 1,008,668	$ 729,706

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Nature of Business

The company is incorporated under the laws of Ontario and is licenced by the Ontario Energy Board (OEB) as an electricity distributor.

Inventory

Inventory is stated at the lower of cost and net realizable value. Cost is generally determined on the average cost basis.

Capital Assets

Capital assets are recorded at cost less accumulated amortization. Amortization is provided on a straight line basis over the assets estimated useful life.

Buildings	- 25	years
Distribution system - overhead	- 25	years
Distribution system - underground	- 25 and 35	years
Distribution transformers	- 25 and 35	years
Distribution meters	- 25 and 35	years
Other equipment - various	- from 4 to 10	years

Goodwill

Goodwill being the excess of cost over assigned values of net assets acquired, is stated at cost. No amortization is provided for goodwill. The value of goodwill is regularly evaluated by reviewing the returns of the related business, taking into account the risk associated with the investment. Any impairment in the value of the goodwill is written off against earnings.

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills.

Revenue Recognition

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. All these charges are flowed through to third parties.

The amounts billed to customers for distribution services is according to rates, both fixed and by volume of power, as approved by the Ontario Energy Board.

Pole rental revenues which is included in other operating revenue is according to rates per pole as established by the Ontario Energy Board.

Late payment charges and interest income is recognized as revenue when earned.

Capital Contributions and Grants	Capital contributions are set up as a capital asset contra account, contributions and grants. This account is amortized on the same basis as the related capital assets.
Payment in Lieu of Taxes	The company accounts for payment in lieu of taxes using the liability payable method based on taxable income. Future income taxes arise from temporary differences in the accounting and tax basis of assets and liabilities. Future tax assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.
Use of Estimates	The preparation of financial statements in accordance with accounting policies established for electric utilities in the Province of Ontario requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.
Basis of Accounting	Revenue and expenditures are reported on the accrual basis of accounting. The accrual basis of accounting recognizes revenues as they are earned and measurable; expenditures are the cost of goods and services acquired in the period whether or not payment has been made or invoices received.

Financial Instruments

The company utilizes various financial instruments. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of the financial instruments approximate their carrying values, unless otherwise noted.

All transactions related to financial instruments are recorded on a trade date basis.

Handbook Section 3862 establishes a fair value hierarchy which includes three levels of inputs that may be used to measure fair value.

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2 - Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or can be corroborated by observable market data for substantially the full term of the assets or liabilities; and
- Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

The company classifies its financial instruments into one of the following categories based on the purpose for which the asset was acquired. There were no transfers between Level 1 and 2 in the year. There were no investments classified as Level 2 or 3. The company's accounting policy for each category is as follows:

Held-for-Trading

This category is comprised of cash and bank (classified as Level 1). They are carried in the balance sheet at fair value with changes in fair value recognized in the statement of operations. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Financial Instruments (continued) Loans and Receivables

These assets are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date or dates or on demand. They arise principally through the provision of goods and services to customers (accounts receivable and unbilled revenue), but also incorporate other types of contractual monetary assets. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest method, less any provision for impairment. Transaction costs related to loans and receivables are expensed as incurred.

Other Financial Liabilities

Other financial liabilities includes all financial liabilities other than those classifed as held-for-trading and comprise accounts payable and accrued liabilities, due to related parties, and bank borrowings. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are expensed as incurred.

Employee Future Benefits

The company provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province of Ontario for employees of municipalities, local boards, and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees contributory earnings. The company recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension provided by the company include medical, dental and life insurance benefits, and accumulated sick leave credits. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expenses is recognized over the period from the entitlement date to the employees retirement date.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

a) International Financial Reporting Standards

The AcSB plans to converge Canadian GAAP with International Financial Reporting Standards ("IFRS") over a transition period expected to end in 2011. The impact of the transition to IFRS on the company's financial statements has yet to be determined.

Regulatory Assets and Liabilities

In accordance with the Canadian Institute of Chartered Accountants Accounting Guideline 19 "disclosure by Entities Subject to Rate Regulations" ("AcG-19") certain costs and variance accounts balances deemed to be "regulatory assets" or "regulatory liabilities" in the local disribution corporation are reflected separately on the company's balance sheet until the manner and timing of disposition is determined by the OEB .

December 31, 2009

1. Inventory

	2009	2008
Balance, beginning of year	$ **75,214**	$ 64,014
Purchases	**115,003**	46,608
Transfer to capital assets	**(137,510)**	(35,408)
Balance, end of year	$ **52,707**	$ 75,214

2. Due to Related Parties

At the end of the year the amounts due to related parties are as follows:

	2009	2008
Due to Shareholder:		
Corporation of the Municipality of Sioux Lookout	$ **412,092**	$ 310,974

These balances are unsecured, interest free, payable on demand and have arisen from the transfer of assets, dividends declared and provision of services referred to below.

The Corporation provides billing services to Corporation of the Municipality of Sioux Lookout for sewer and water. At year end, the uncollected bills from customers was $173,092 (2008 - $125,974). As well there was a dividend declared and payable of $239,000 (2008 - $185,000). During the year the company billed electricity and services to the shareholder in the amount of $680,484 (2008 - $658,767).

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

December 31, 2009

3. Regulatory Assets (Liabilities)

Under Bill 210, certain costs and variance account balances are deemed to be "regulatory assets (liabilities)" in accordance with the OEB Accounting Procedures Handbook. These assets are to be reflected on the Corporation's balance sheet. The OEB has granted the Corporation permission to recover the regulatory assets when establishing its distribution rates.

	2009	2008
Retail settlement variances	**$ 14,968**	$ 15,973
Wholesale market service variances	**(64,150)**	(7,798)
Network charges variances	**(133,078)**	(135,040)
Connection charges variances	**(189,817)**	(449,692)
Power charges variances	**286,695**	745,244
Smart meter rate adder funding	**(114,435)**	5,255
Smart meter deferral	**680,116**	-
Disposition and recovery of regulatory balances	**153,318**	(3,161)
	$ 633,617	$ 170,781

4. Capital Assets

	2009		2008	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Buildings	**$ 91,864**	**$ 33,673**	$ 91,864	$ 29,998
Distribution system-overhead	**4,188,807**	**1,303,488**	4,016,093	1,135,936
Distribution system - underground	**971,609**	**291,107**	933,687	252,242
Distribution transformers	**1,476,743**	**461,301**	1,470,153	402,232
Distribution meters	**390,397**	**94,937**	320,348	87,073
Other equipment - various	**746,220**	**545,604**	671,770	470,078
Contributions and grants	**(704,417)**	**(141,756)**	(608,208)	(113,580)
Construction in progress	**2,291**	**-**	3,512	-
	$ 7,163,514	**$ 2,588,354**	$ 6,899,219	$ 2,263,979
Net book value		**$ 4,575,160**		$ 4,635,240

December 31, 2009

5. Bank Indebtedness

		2009		2008
Demand instalment loan, repayable at $5,814 including interest at 4.7%, secured by a general security agreement covering all assets; due 2024	$	**735,502**	$	-
Demand instalment loan, repayable at $15,500 per month plus interest at prime, secured by a general security agreement covering all assets; due 2022		**2,316,990**		2,502,989
	$	**3,052,492**	$	2,502,989

The demand instalment loans are secured by a general security agreement covering all assets and are guaranteed by Corporation of the Municipality of Sioux Lookout.

The company has an unused operating line of credit of $175,000 with terms of due on demand and bears interest at the bank's prime rate calculated and payable monthly.

At December 31, 2009 the fair value of the bank indebtedness was $2,807,585 calculated based on the amount of future cash flows associated with each instrument discounted using an estimate of what the company's current borrowing rate for similar debt instruments of comparable maturity would be.

The agreement governing the demand instalment loan facility contains certain covenants regarding (i) debt servicing ratios, (ii) negative pledge where no lien can be assigned against assets, and (iii) the bank must permit any material change to the company.

The company has violated the debt servicing ratio covenant. Except for the debt servicing covenant, the company was in compliance with all covenants as at December 31, 2009.

6. Employee Benefits Payable

		2009		2008
Vacation pay	$	**29,045**	$	22,098
Vested sick leave		**41,004**		39,811
Banked overtime		**4,625**		2,900
Post employment benefits		**41,960**		44,647
	$	**116,634**	$	109,456

The post employment benefits is estimated based on the premiums paid to employees from date eligible to retire, until age 65. The estimate assumes an inflation rate of 3.46% and a discount rate of 4%.

December 31, 2009

7. Share Capital

The authorized class A preference share capital of the company is an unlimited number of non-voting shares, with a stated value equal to the consideration received on issue, redeemable and retractable at $1,000 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class B preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $100 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class C preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class D preference share capital of the company is an unlimited number of voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized common share capital of the company is an unlimited number of shares.

The issued share capital is as follows:

	2009	2008
100 Common shares	**$ 2,789,823**	$ 2,789,823

8. Financial Income and Expense

	2009	2008
Interest on assets held-for-trading	**$ 17,056**	$ 44,894
Interest expense on financial liabilities measured at amortized cost	**65,527**	135,717
Interest expense on financial assets measured at fair value	**60,241**	60,765
	125,768	196,482
Net finance costs	**$ (108,712)**	$ (151,588)

December 31, 2009

9. Other Operating Revenue

	2009	2008
Late payment charges	$ **50,000**	$ 40,428
Interest income	**17,056**	44,894
Pole rentals	**40,023**	38,630
Change in occupancy charges	**17,070**	19,410
Sentinel light rental	**9,430**	9,691
Sundry	**4,423**	13,664
	$ **138,002**	$ 166,717

10. Pension Agreement

The company makes contributions to the Ontario Municipal Employers Retirement Fund (OMERS), which is a multi-employer plan, on behalf of seven members of its staff. The plan is a deferred benefit plan which specifies the amount of the retirement benefit to be received by the employee based on the length of service and rate of pay.

During the year ended December 31, 2009 the Board contributed $40,779 (2008 - $36,012) to the plan. As this is a multi-employer pension plan, these contributions are the Board's pension benefit expenses. No pension liability for this type of plan is included in the Board's financial statements.

11. Supplementary Cash Flow Information

	2009	2008
Interest paid	$ **125,768**	$ 203,763
Payment in lieu of taxes paid	$ **25,820**	$ 23,681

12. Amortization of Capital Assets

		2009		2008
Amortization of building and distribution equipment	$	**286,564**	$	274,038
Amortization of office equipment		**8,159**		3,080
Amortization of contributions and grants		**(28,176)**		(24,328)
		266,547		252,790
Amortization of other capital assets included in relevant expense categories				
Rolling stock		**48,130**		54,308
Operations and maintenance		**16,728**		16,021
Sentinel lights		**2,509**		2,328
	$	**333,914**	$	325,447

13. Commitments

The company has entered into an operating lease for certain equipment (Altec Aerial Device). The equipment is leased at $3,176 per month under a lease expiring in 2013.

The minimum annual lease payments for the next four years are as follows:

2010	$	38,112
2011		38,112
2012		38,112
2013		25,408

14. Fair Value of Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, and accounts payable and accrued liabilities approximate their carrying amounts because of the short-term maturity of these instruments.

The fair value of the due to related parties amount has not not been determined as disclosed in Note 2.

The fair value of bank indebtedness is disclosed in Note 5.

15. Loss on Impairment of Goodwill

During the year there were numerous pervasive factors in the environment that indicated the goodwill should be written off. Other utility companies in similar markets have conducted valuations, using the discounted cash flow method, and results of their valuations have indicated an impairment of goodwill.

16. Financial Instrument Risk Exposure and Management

The Board has overall responsibility for the determination of the company's risk management objectives and policies while retaining ultimate responsibility for them. It has delegated the authority for designing and operating processes that ensure the effectiveness of the objectives and policies to the company's finance function. The Board receives quarterly financial reports from the manager through which it reviews the effectiveness of the processes put in place and the results of operations.

Credit Risk

The company has a policy it follows to ensure that the accounts receivables are collected on a timely basis. When a customer account goes into arrears Thunder Bay Hydro Inc. calls the customer in an effort to secure payment. In the event that the calls fail, Sioux Lookout Hydro Inc. will follow up with a letter that explains to the customer the ramifications of not paying their account. Once several days pass the services provided to the customer will be cut off. This process is followed unless the Board directs management to exclude certain customers groups from having their services cut off.

If a customer leaves their residence and the above collection process is not successful, Sioux Lookout Hydro Inc. will engage the services of a collection bureau to pursue these customer accounts. When an account is transferred to a collection bureau management sets these accounts up as doubtful accounts. At year end the allowance for doubtful accounts balance was $61,898 (2008 - $58,703). When all avenues to collect outstanding receivables have been exhausted management, with Board approval, will write off the receivables. During the year the company wrote off $42,954 of outstanding receivables (2008 - $36,991).

Sioux Lookout Hydro Inc. is in the normal course of operations, exposed to credit risk from having bank account balances over the amounts insured by the Canadian Deposit Insurance Corporation.

Liquidity Risk

The company's policy is to ensure that it will always have sufficient cash to allow it to meet its liabilities when they become due. Management reconciles its bank on a monthly basis and it funds temporary cash shortages through a line of credit with the bank.

16. Financial Instrument Risk Exposure and Management (continued)

The following table illustrates the contractual maturity analysis of the company's financial liabilities. It is prepared on a gross basis and assumes the bank demand loan is repaid according to the instalment schedule and prevailing interest rates (prime).

	2010	2011	2012	2013	2014	Thereafter	Total
Non-derivative financial instruments	$ 305,987	$ 301,802	$ 297,617	$ 293,432	$ 289,247	$ 2,173,292	$3,661,377

Market Risk

Market risk arises from the company's floating rate demand loan and fixed rate loan.

The annualized effect of a 1.0% decrease in the interest rate at the balance sheet date on the floating rate demand loan carried at that date would, all other variables held constant; have resulted in an increase in post-tax profit for the year of $31,500. A 1.0% increase in the interest rate would, on the same basis, have decreased post-tax profit by the same amount.

Capital Disclosures

Sioux Lookout Hydro Inc. manages its capital in a manner consistent with the risk characteristics of the assets it holds. All financing, including equity and debt are analyzed by management and approved by the board of directors.

The company's objectives when managing capital are:

a) to safeguard the company's ability to continue as a going concern and provide returns for shareholders;

b) to maintain a safe and reliable electricity distribution system.

The company is meeting its objective of managing capital through its detailed review and preparing short-term and long-term cash flow analysis to ensure an adequate amount of liquidity and monthly review of financial results.

There have been no changes in the company's approach to capital management from the previous years.

17. Change in Accounting Policy

Effective for year ends beginning on or after January 1, 2009, the Canadian Institute of Chartered Accountants ('CICA') amended the CICA Handbook Section 1100, Generally Accepted Accounting Principles, Section 3465, Income Taxes and Accounting Guideline 19 - Disclosures by Entities Subject to Rate-Regulation.

The revision to Section 1100 removed the temporary exemption pertaining to the application of that Section to the recognition and measurement of assets and liabilities arising from rate-regulation. Accounting Guideline 19 amended certain disclosures as a result of the changes to the other Sections. Adoption of these amendments did not affect the company's results of operations and financial position.

The amendments to Section 3465 require rate-regulated enterprises to recognize future income tax liabilities and assets, as well as, a regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to future customers and to present these amounts on a gross basis in the financial statements. Entities in this sector were previously exempted from the requirement to recognized future income taxes. The company adopted this new accounting recommendation without the restatement of prior year's figures by making a cumulative catch-up adjustment of $76,686 to opening retained earnings in the current year and applying the new accounting policy to events and transactions occuring after the date of the change.

18. Correction of Prior Period Error

During the year an error was found in the calculation of interest on the regulatory assets. The interest was being calculated on the net change in the regulatory assets each month. Instead, the interest should have been calculated based on the monthly accumulated regulatory asset balance. As a result, the prior years financial statements have been retroactively restated by increasing the other operating revenue by $11,475, increasing the payment in lieu of taxes by $2,295, increasing the regulatory assets by $97,828, increasing the taxes payable by $19,500, and increasing the prior year opening retained earnings by $69,148. The cumulative effect on the current year retained earnings is an increase to the retained earnings of $78,328.

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2010

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2010

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Sioux Lookout Hydro Inc.

We have audited the accompanying financial statements of Sioux Lookout Hydro Inc., which comprise the balance sheet as at December 31, 2010, and the statements of retained earnings, operations and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement. An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Sioux Lookout Hydro Inc. for the year ended December 31, 2010 and the results of its operations and cash flows for the year then ended, in accordance with Canadian generally accepted accounting principles.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Dryden, Ontario
April 14, 2011

Sioux Lookout Hydro Inc.
Balance Sheet

December 31	2010	2009
Assets		
Current		
Cash and bank	$ 793,425	$ 1,008,668
Accounts receivable	835,605	536,652
Unbilled revenue	1,134,908	1,060,301
Inventory (Note 1)	44,830	52,707
Prepaid expenses	35,783	35,031
Taxes receivable	16,493	-
	2,861,044	2,693,359
Regulatory assets (Note 3)	167,591	633,617
Capital assets (Note 4)	4,528,276	4,575,160
Future income tax assets	133,236	113,196
	$ 7,690,147	$ 8,015,332
Liabilities and Shareholder's Equity		
Current		
Bank indebtedness (Note 5)	$ 2,830,519	$ 3,052,492
Accounts payable and accrued liabilities	1,424,508	1,359,672
Employee benefits payable (Note 6)	125,526	116,634
Taxes payable	-	65,898
Customer deposits	134,816	130,667
Due to related parties (Note 2)	212,956	412,092
	4,728,325	5,137,455
Shareholder's equity		
Share capital (Note 7)	2,789,823	2,789,823
Retained earnings	171,999	88,054
	2,961,822	2,877,877
	$ 7,690,147	$ 8,015,332

On behalf of the Board:

____________________________ Director

____________________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Retained Earnings

For the year ended December 31		2010		2009
Retained earnings, beginning of year	$	**88,054**	$	157,261
Net income for the year		**296,901**		93,107
Change in accounting policy (Note 17)		**-**		76,686
Dividends		**(212,956)**		(239,000)
Retained earnings, end of year	$	**171,999**	$	88,054

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Operations

For the year ended December 31		2010		2009	
Revenue					
Sale of energy					
Residential and general	$	**6,736,018**	**97.1 %**	$ 5,150,127	97.9 %
Street lighting		**124,729**	**1.8 %**	102,052	1.9 %
Unbilled revenue adjustment		**74,608**	**1.1 %**	10,869	0.2 %
		6,935,355	**100 %**	5,263,048	100 %
Cost of bulk power purchased		**5,202,374**	**75.0 %**	3,497,911	66.5 %
Gross margin on energy sold		**1,732,981**	**25.0 %**	1,765,137	33.5 %
Other operating revenue (Note 9)		**130,154**	**2.0 %**	138,002	2.6 %
		1,863,135	**27.0 %**	1,903,139	36.1 %
Expenditures					
Administration		**474,648**	**6.7 %**	513,786	9.8 %
Amortization		**282,949**	**4.1 %**	269,056	5.1 %
Interest and bank charges		**161,091**	**2.4 %**	125,768	2.4 %
Operation maintenance		**635,137**	**9.3 %**	564,734	10.7 %
		1,553,825	**22.5 %**	1,473,344	28.0 %
Income before other item and payment in lieu of taxes		**309,310**	**4.5 %**	429,795	8.1 %
Other item					
Loss on impairment of goodwill (Note 15)		**-**	**- %**	(300,979)	(5.7)%
Income before payment in lieu of taxes		**309,310**	**4.5 %**	128,816	2.4 %
Payment in lieu of taxes					
Payment in lieu of taxes		**32,449**	**0.5 %**	72,218	1.4 %
Future payment in lieu recoverable		**(20,040)**	**(0.3)%**	(36,509)	(0.7)%
		12,409	**0.2 %**	35,709	0.7 %
Net income for the year	$	**296,901**	**4.3 %**	$ 93,107	1.7 %

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Cash Flows

For the year ended December 31	2010	2009
Cash provided by (used in)		
Operating activities		
Net income for the year	$ 296,901	$ 93,107
Items not involving cash		
Amortization of capital assets (Note 12)	344,552	333,914
Future income taxes (recovery)	(20,040)	(36,509)
(Gain) loss on disposal of capital assets	(633)	16,347
Loss on impairment of goodwill	-	300,979
	620,780	707,838
Changes in non-cash working capital balances		
Accounts receivable	(298,953)	193,357
Unbilled revenue	(74,607)	(10,869)
Inventory	7,877	22,507
Prepaid expenses	(752)	5,896
Accounts payable and accrued liabilities	64,836	(368,379)
Employee benefits payable	8,892	7,178
Taxes receivable	(82,379)	49,120
Customer deposits	4,149	13,712
	249,843	620,360
Investing activities		
Purchase of capital assets	(297,666)	(290,548)
Increase in regulatory assets (liabilities)	466,026	(462,836)
Proceeds on sale of capital assets	613	367
	168,973	(753,017)
Financing activities		
Increase (decrease) in bank indebtedness	(221,973)	549,503
Dividends paid	(212,956)	(239,000)
Due to/from related parties	(199,130)	101,116
	(634,059)	411,619
Increase (decrease) in cash during the year	(215,243)	278,962
Cash and bank, beginning of year	1,008,668	729,706
Cash and bank, end of year	$ 793,425	$ 1,008,668

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Nature of Business

The company is incorporated under the laws of Ontario and is licenced by the Ontario Energy Board (OEB) as an electricity distributor.

Inventory

Inventory is stated at the lower of cost and net replacement cost. Cost is generally determined on the average cost basis.

Capital Assets

Capital assets are recorded at cost less accumulated amortization. Amortization is provided on a straight line basis over the assets estimated useful life.

Buildings	- 25	years
Distribution system - overhead	- 25	years
Distribution system - underground	- 25 and 35	years
Distribution transformers	- 25 and 35	years
Distribution meters	- 25 and 35	years
Other equipment - various	- from 4 to 10 years	

Regulatory Assets and Liabilities

In accordance with the Canadian Institute of Chartered Accountants Accounting Guideline 19 "disclosure by Entities Subject to Rate Regulations" ("AcG-19") certain costs and variance accounts balances deemed to be "regulatory assets" or "regulatory liabilities" in the local disribution corporation are reflected separately on the company's balance sheet until the manner and timing of disposition is determined by the OEB .

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills.

Revenue Recognition

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. All these charges are flowed through to third parties.

The amounts billed to customers for distribution services is according to rates, both fixed and by volume of power, as approved by the Ontario Energy Board.

Pole rental revenues which is included in other operating revenue is according to rates per pole as established by the Ontario Energy Board and is recognized as revenue as service is performed.

Late payment charges and interest income is recognized as revenue when earned.

Other miscellaneous income is recognized as service is performed.

Capital Contributions and Grants

Capital contributions are set up as a capital asset contra account, contributions and grants. This account is amortized on the same basis as the related capital assets.

Payment in Lieu of Taxes

The company accounts for payment in lieu of taxes using the liability payable method based on taxable income. Future income taxes arise from temporary differences in the accounting and tax basis of assets and liabilities. Future tax assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

Basis of Accounting

Revenue and expenditures are reported on the accrual basis of accounting. The accrual basis of accounting recognizes revenues as they are earned and measurable; expenditures are the cost of goods and services acquired in the period whether or not payment has been made or invoices received.

Use of Estimates

The preparation of financial statements in accordance with accounting policies established for electric utilities in the Province of Ontario requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

The company utilizes various financial instruments. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of the financial instruments approximate their carrying values, unless otherwise noted.

All transactions related to financial instruments are recorded on a trade date basis.

Handbook Section 3862 establishes a fair value hierarchy which includes three levels of inputs that may be used to measure fair value.

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2 - Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or can be corroborated by observable market data for substantially the full term of the assets or liabilities; and
- Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

The company classifies its financial instruments into one of the following categories based on the purpose for which the asset was acquired. There were no transfers between Level 1 and 2 in the year. There were no investments classified as Level 2 or 3. The company's accounting policy for each category is as follows:

Held-for-Trading

This category is comprised of cash and bank (classified as Level 1). They are carried in the balance sheet at fair value with changes in fair value recognized in the statement of operations. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Financial Instruments (continued) Loans and Receivables

These assets are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date or dates or on demand. They arise principally through the provision of goods and services to customers (accounts receivable and unbilled revenue), but also incorporate other types of contractual monetary assets. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest method, less any provision for impairment. Transaction costs related to loans and receivables are expensed as incurred.

Other Financial Liabilities

Other financial liabilities includes all financial liabilities other than those classifed as held-for-trading and comprise accounts payable and accrued liabilities, due to related parties, and bank borrowings. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are expensed as incurred.

Employee Future Benefits

The company provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province of Ontario for employees of municipalities, local boards, and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees contributory earnings. The company recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension provided by the company include the payments of the premiums on medical, dental and life insurance benefits, and accumulated sick leave credits. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expenses is recognized over the period from the entitlement date to the employees retirement date.

New Accounting Pronouncements

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date.

The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. At this time, the Corporation believes that the impact on its financial statements could be material.

On September 10, 2010, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board ("IASB") in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. Subsequently, the Canadian Securities Administrators announced that entities subject to rate regulation may defer the adoption of IFRS for up to one year, consistent with the one year deferral granted by the AcSB.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting ("RRA") standard under IFRS and the potential material impact of RRA on the Corporation's financial statements, the Corporation has decided to elect the optional one-year deferral of its adoption of IFRS. Accordingly, the Corporation will continue to prepare its financial statements in accordance with Canadian GAAP accounting standards in Part V of the CICA Handbook for 2011.

As a result of these developments related to IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Corporation cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operations. Although the Corporation has completed a detailed assessment of the accounting and disclosure differences between Canadian GAAP and IFRS, in light of the one-year deferral, this assessment will be revisited due to changes to standards during this period. The Corporation will continue to actively monitor IASB developments with respect to RRA and non-RRA IFRS developments and their potential impacts.

December 31, 2010

1. Inventory

		2010		2009
Balance, beginning of year	$	**52,707**	$	75,214
Purchases		**100,773**		115,003
Transfer to capital assets		**(108,650)**		(137,510)
Balance, end of year	$	**44,830**	$	52,707

2. Due to Related Parties

At the end of the year the amounts due to related parties are as follows:

		2010		2009
Due to Shareholder:				
Corporation of the Municipality of Sioux Lookout	$	**212,956**	$	412,092

These balances are unsecured, interest free, payable on demand and have arisen from the transfer of assets, dividends declared and provision of services referred to below.

In the prior year the Corporation provided billing services to Corporation of the Municipality of Sioux Lookout for sewer and water. The Corporation provided these services in the current year until May. At year end, the uncollected bills from customers was $nil (2009 - $173,092). As well there was a dividend declared and payable of $212,956 (2009 - $239,000). During the year the company billed electricity and services to the shareholder in the amount of $749,517 (2009 - $680,484).

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

3. Regulatory Assets (Liabilities)

Under Bill 210, certain costs and variance account balances are deemed to be "regulatory assets (liabilities)" in accordance with the OEB Accounting Procedures Handbook. These assets are to be reflected on the Corporation's balance sheet. The OEB has granted the Corporation permission to recover the regulatory assets when establishing its distribution rates.

	2010	2009
Retail settlement variances	$ 13,471	$ 14,968
Wholesale market service variances	(185,064)	(64,150)
Network charges variances	(4,281)	(133,078)
Connection charges variances	285,994	(189,817)
Power charges variances	(786,312)	286,695
Smart meter rate adder funding	(114,667)	(52,160)
Smart meter deferral	762,066	680,116
Disposition and recovery of regulatory balances	196,384	91,043
	$ 167,591	$ 633,617

4. Capital Assets

	2010		2009	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Buildings	$ 91,864	$ 37,347	$ 91,864	$ 33,673
Distribution system-overhead	4,388,392	1,479,023	4,188,807	1,303,488
Distribution system - underground	1,001,186	331,154	971,609	291,107
Distribution transformers	1,545,612	523,126	1,476,743	461,301
Distribution meters	447,604	114,629	390,397	94,937
Other equipment - various	774,590	617,002	746,220	545,604
Contributions and grants	(817,216)	(169,933)	(704,417)	(141,756)
Construction in progress	28,592	-	2,291	-
	$ 7,460,624	$ 2,932,348	$ 7,163,514	$ 2,588,354
Net book value		$ 4,528,276		$ 4,575,160

December 31, 2010

5. Bank Indebtedness

	2010	2009
Demand instalment loan, repayable at $5,814 including interest at 4.7%, secured by a general security agreement covering all assets; due 2024	$ **699,530**	$ 735,502
Demand instalment loan, repayable at $15,500 per month plus interest at prime, secured by a general security agreement covering all assets; due 2022	**2,130,989**	2,316,990
	$ **2,830,519**	$ 3,052,492

The demand instalment loans are secured by a general security agreement covering all assets and are guaranteed by Corporation of the Municipality of Sioux Lookout.

The company has an unused operating line of credit of $175,000 with terms of due on demand and bears interest at the bank's prime rate calculated and payable monthly.

At December 31, 2010 the fair value of the bank indebtedness was $2,626,013 calculated based on the amount of future cash flows associated with each instrument discounted using 5% which is an estimate of what the company's current borrowing rate for similar debt instruments of comparable maturity would be.

The agreement governing the demand instalment loan facility contains certain covenants regarding (i) debt servicing ratios, (ii) negative pledge where no lien can be assigned against assets, and (iii) the bank must approve any material change to the company.

6. Employee Benefits Payable

	2010	2009
Vacation pay	$ **34,806**	$ 29,045
Vested sick leave	**42,234**	41,002
Banked overtime	**2,498**	4,625
Post employment benefits	**45,988**	41,962
	$ **125,526**	$ 116,634

The post employment benefits is estimated based on the premiums paid to employees from date eligible to retire, until age 65. The estimate assumes an inflation rate of 3.46% and a discount rate of 4%.

December 31, 2010

7. Share Capital

The authorized class A preference share capital of the company is an unlimited number of non-voting shares, with a stated value equal to the consideration received on issue, redeemable and retractable at $1,000 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class B preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $100 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class C preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class D preference share capital of the company is an unlimited number of voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized common share capital of the company is an unlimited number of shares.

The issued share capital is as follows:

		2010	2009
100	Common shares	$ 2,789,823	$ 2,789,823

8. Financial Income and Expense

	2010	2009
Interest on assets held-for-trading	$ 13,536	$ 17,056
Interest expense on financial liabilities measured at amortized cost	30,521	65,527
Interest expense on financial assets measured at fair value	108,122	60,241
	138,643	125,768
Net finance costs	$ (125,107)	$ (108,712)

December 31, 2010

9. Other Operating Revenue

		2010		2009
Late payment charges	$	**37,665**	$	50,000
Interest income		**13,536**		17,056
Pole rentals		**40,279**		40,023
Change in occupancy charges		**16,260**		17,070
Sentinel light rental		**9,838**		9,430
Sundry		**12,576**		4,423
	$	**130,154**	$	138,002

10. Pension Agreement

The company makes contributions to the Ontario Municipal Employers Retirement Fund (OMERS), which is a multi-employer plan, on behalf of eight members of its staff. The plan is a deferred benefit plan which specifies the amount of the retirement benefit to be received by the employee based on the length of service and rate of pay.

During the year ended December 31, 2010 the Board contributed $42,407 (2009 - $40,779) to the plan. As this is a multi-employer pension plan, these contributions are the Board's pension benefit expenses. No pension liability for this type of plan is included in the Board's financial statements.

11. Supplementary Cash Flow Information

		2010		2009
Interest paid	$	**138,643**	$	125,768
Payment in lieu of taxes paid	$	**52,304**	$	25,820

December 31, 2010

12. Amortization of Capital Assets

	2010	2009
Amortization of building and distribution equipment	$ **300,774**	$ 286,564
Amortization of office equipment	**8,009**	8,159
Amortization of contributions and grants	**(28,177)**	(28,176)
	280,606	266,547
Amortization of other capital assets included in relevant expense categories		
Rolling stock	**46,249**	48,130
Operations and maintenance	**15,353**	16,728
Sentinel lights	**2,344**	2,509
	$ **344,552**	$ 333,914

13. Commitments

The company has entered into an operating lease for certain equipment (Altec Aerial Device). The equipment is leased at $3,176 per month under a lease expiring in 2013.

The minimum annual lease payments for the next three years are as follows:

2011	$ 38,112
2012	38,112
2013	25,408

14. Fair Value of Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, and accounts payable and accrued liabilities approximate their carrying amounts because of the short-term maturity of these instruments.

The fair value of the due to related parties amount has not not been determined as disclosed in Note 2.

The fair value of bank indebtedness is disclosed in Note 5.

December 31, 2010

15. Loss on Impairment of Goodwill

During the prior year there were numerous pervasive factors in the environment that indicated the goodwill should be written off. Other utility companies in similar markets have conducted valuations, using the discounted cash flow method, and results of their valuations have indicated an impairment of goodwill.

16. Financial Instrument Risk Exposure and Management

The Board has overall responsibility for the determination of the company's risk management objectives and policies while retaining ultimate responsibility for them. It has delegated the authority for designing and operating processes that ensure the effectiveness of the objectives and policies to the company's finance function. The Board receives quarterly financial reports from the manager through which it reviews the effectiveness of the processes put in place and the results of operations.

Credit Risk

The company has a policy it follows to ensure that the accounts receivables are collected on a timely basis. When a customer account goes into arrears Thunder Bay Hydro Inc. calls the customer in an effort to secure payment. In the event that the calls fail, Sioux Lookout Hydro Inc. will follow up with a letter that explains to the customer the ramifications of not paying their account. Once several days pass the services provided to the customer will be cut off. This process is followed unless the Board directs management to exclude certain customers groups from having their services cut off.

If a customer leaves their residence and the above collection process is not successful, Sioux Lookout Hydro Inc. will engage the services of a collection bureau to pursue these customer accounts. When an account is transferred to a collection bureau management sets these accounts up as doubtful accounts. At year end the allowance for doubtful accounts balance was $90,548 (2009 - $61,898). When all avenues to collect outstanding receivables have been exhausted management, with Board approval, will write off the receivables. During the year the company wrote off $nil of outstanding receivables (2009 - $42,954).

Sioux Lookout Hydro Inc. is in the normal course of operations, exposed to credit risk from having bank account balances over the amounts insured by the Canadian Deposit Insurance Corporation. The interest rate on the bank account is prime less 2.

Liquidity Risk

The company's policy is to ensure that it will always have sufficient cash to allow it to meet its liabilities when they become due. Management reconciles its bank on a monthly basis and it funds temporary cash shortages through a line of credit with the bank.

December 31, 2010

16. Financial Instrument Risk Exposure and Management (continued)

The following table illustrates the contractual maturity analysis of the company's financial liabilities. It is prepared on a gross basis and assumes the bank demand loan is repaid according to the instalment schedule and prevailing interest rates (prime).

	2011	2012	2013	2014	2015	Thereafter	Total
Non-derivative financial instruments	$ 317,145	$ 311,565	$ 305,985	$ 300,405	$ 294,825	$ 1,917,703	$3,447,628

Market Risk

Market risk arises from the company's floating rate demand loan and fixed rate loans.

The annualized effect of a 1.0% decrease in the interest rate at the balance sheet date on the floating rate demand loan carried at that date would, all other variables held constant; have resulted in an increase in post-tax profit for the year of $31,500. A 1.0% increase in the interest rate would, on the same basis, have decreased post-tax profit by the same amount.

The annualized effect of a 1.0% decrease in the interest rate at the balance sheet on the fixed rate loan carried at that date would, all other variables held constant; have resulted in a decrease in the fair value of the loan of $44,000. A 1.0% increase in the interest rate would, on the same basis, have increased the fair value by the same amount.

17. Change in Accounting Policy

Effective for year ends beginning on or after January 1, 2009, the Canadian Institute of Chartered Accountants ('CICA') amended the CICA Handbook Section 1100, Generally Accepted Accounting Principles, Section 3465, Income Taxes and Accounting Guideline 19 - Disclosures by Entities Subject to Rate-Regulation.

The revision to Section 1100 removed the temporary exemption pertaining to the application of that Section to the recognition and measurement of assets and liabilities arising from rate-regulation. Accounting Guideline 19 amended certain disclosures as a result of the changes to the other Sections. Adoption of these amendments did not affect the company's results of operations and financial position.

The amendments to Section 3465 require rate-regulated enterprises to recognize future income tax liabilities and assets, as well as, a regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to future customers and to present these amounts on a gross basis in the financial statements. Entities in this sector were previously exempted from the requirement to recognized future income taxes. The company adopted this new accounting recommendation without the restatement of prior year's figures by making a cumulative catch-up adjustment of $76,686 to opening retained earnings in the current year and applying the new accounting policy to events and transactions occuring after the date of the change.

18. Capital Disclosures

Sioux Lookout Hydro Inc. manages its capital in a manner consistent with the risk characteristics of the assets it holds. All financing, including equity and debt are analyzed by management and approved by the board of directors.

The company's objectives when managing capital are:

a) to safeguard the company's ability to continue as a going concern and provide returns for shareholders;

b) to maintain a safe and reliable electricity distribution system.

The company is meeting its objective of managing capital through its detailed review and preparing short-term and long-term cash flow analysis to ensure an adequate amount of liquidity and monthly review of financial results.

There have been no changes in the company's approach to capital management from the previous years.

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2011

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2011

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Sioux Lookout Hydro Inc.

We have audited the accompanying financial statements of Sioux Lookout Hydro Inc., which comprise the balance sheet as at December 31, 2011, and the statements of retained earnings, operations and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement. An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Sioux Lookout Hydro Inc. for the year ended December 31, 2011 and the results of its operations and cash flows for the year then ended, in accordance with Canadian generally accepted accounting principles.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Dryden, Ontario
March 22, 2012

Sioux Lookout Hydro Inc.
Balance Sheet

December 31		2011		2010
Assets				
Current				
Cash and bank	$	**944,586**	$	793,425
Accounts receivable		**787,347**		818,462
Unbilled revenue		**1,135,299**		1,134,908
Inventory (Note 1)		**61,659**		44,830
Prepaid expenses		**35,711**		35,783
Taxes receivable		**15,111**		16,493
		2,979,713		2,843,901
Regulatory assets (Note 3)		**98,340**		184,735
Property, plant and equipment (Note 4)		**4,467,728**		4,528,276
Future income tax assets		**136,243**		133,236
	$	**7,682,024**	$	7,690,148
Liabilities and Shareholder's Equity				
Current				
Bank indebtedness (Note 5)	$	**2,606,819**	$	2,830,520
Accounts payable and accrued liabilities		**1,547,188**		1,424,508
Employee benefits payable (Note 6)		**120,488**		125,526
Customer deposits		**137,538**		134,816
Due to related parties (Note 2)		**250,000**		212,956
		4,662,033		4,728,326
Shareholder's equity				
Share capital (Note 7)		**2,789,823**		2,789,823
Retained earnings		**230,168**		171,999
		3,019,991		2,961,822
	$	**7,682,024**	$	7,690,148

On behalf of the Board:

____________________________ Director

____________________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Retained Earnings

For the year ended December 31		2011		2010
Retained earnings, beginning of year	$	**171,999**	$	88,054
Net income for the year		**308,169**		296,901
Dividends		**(250,000)**		(212,956)
Retained earnings, end of year	$	**230,168**	$	171,999

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Operations

For the year ended December 31		2011			2010	
Revenue						
Sale of energy						
Residential and general	$	**7,765,733**	**98.2 %**	$	6,748,600	97.1 %
Street lighting		**141,197**	**1.8 %**		124,644	1.8 %
Unbilled revenue adjustment		**390**	**- %**		74,608	1.1 %
		7,907,320	**100 %**		6,947,852	100 %
Cost of bulk power purchased		**6,168,149**	**78.0 %**		5,214,871	75.1 %
Gross margin on energy sold		**1,739,171**	**22.0 %**		1,732,981	24.9 %
Other operating revenue (Note 9)		**133,029**	**1.8 %**		130,154	1.9 %
		1,872,200	**23.8 %**		1,863,135	26.7 %
Expenditures						
Administration		**514,471**	**6.4 %**		474,648	6.8 %
Amortization		**279,372**	**3.5 %**		282,949	4.1 %
Interest and bank charges		**144,873**	**1.9 %**		161,091	2.3 %
Operation maintenance		**595,583**	**7.6 %**		635,137	9.1 %
		1,534,299	**19.4 %**		1,553,825	22.3 %
Income before other item and payment in lieu of taxes		**337,901**	**4.3 %**		309,310	4.4 %
Other item						
Loss on impairment of goodwill (Note 15)		**-**	**- %**		-	- %
Income before payment in lieu of taxes		**337,901**	**4.3 %**		309,310	4.4 %
Payment in lieu of taxes						
Payment in lieu of taxes		**32,739**	**0.4 %**		32,449	0.5 %
Future payment in lieu recoverable		**(3,007)**	**- %**		(20,040)	(0.3)%
		29,732	**0.4 %**		12,409	0.2 %
Net income for the year	$	**308,169**	**3.9 %**	$	296,901	4.2 %

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Cash Flows

For the year ended December 31	2011	2010
Cash provided by (used in)		
Operating activities		
Net income for the year	$ **308,169**	$ 296,901
Items not involving cash		
Amortization of property, plant and equipment (Note 12)	**304,303**	344,552
Future income taxes recovered	**(3,007)**	(20,040)
Gain on disposal of property,plant and equipment	**-**	(633)
	609,465	620,780
Changes in non-cash working capital balances		
Accounts receivable	**31,115**	(298,953)
Unbilled revenue	**(391)**	(74,607)
Inventory	**(16,829)**	7,877
Prepaid expenses	**72**	(752)
Accounts payable and accrued liabilities	**122,680**	64,836
Employee benefits payable	**(5,038)**	8,892
Taxes receivable	**1,383**	(82,379)
Customer deposits	**2,720**	4,149
	745,177	249,843
Investing activities		
Purchase of property, plant and equipment	**(243,754)**	(297,666)
Increase in regulatory assets (liabilities)	**86,395**	466,026
Proceeds on sale of property, plant and equipment	**-**	613
	(157,359)	168,973
Financing activities		
Decrease in bank indebtedness	**(223,701)**	(221,973)
Dividends paid	**-**	(212,956)
Due to/from related parties	**(212,956)**	(199,130)
	(436,657)	(634,059)
Increase (decrease) in cash during the year	**151,161**	(215,243)
Cash and bank, beginning of year	**793,425**	1,008,668
Cash and bank, end of year	$ **944,586**	$ 793,425

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2011

Nature of Business

The company is incorporated under the laws of ON and is licensed by the Ontario Energy Board (OEB) as an electricity distributor.

Inventory

Inventory is stated at the lower of cost and net replacement cost. Cost is generally determined on the average cost basis.

Property, plant and equipment

Property, plant and equipment are recorded at cost less accumulated amortization. Amortization is provided on a straight line basis over the assets estimated useful life.

Buildings	- 25	years
Distribution system - overhead	- 25	years
Distribution system - underground	- 25 and 35	years
Distribution transformers	- 25 and 35	years
Distribution meters	- 25 and 35	years
Other equipment - various	- from 4 to 10	years

Regulatory Assets and Liabilities

In accordance with the Canadian Institute of Chartered Accountants Accounting Guideline 19 "disclosure by Entities Subject to Rate Regulations" ("AcG-19") certain costs and variance accounts balances deemed to be "regulatory assets" or "regulatory liabilities" in the local distribution corporation are reflected separately on the company's balance sheet until the manner and timing of disposition is determined by the OEB .

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills.

December 31, 2011

Revenue Recognition

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. All these charges are flowed through to third parties.

The amounts billed to customers for distribution services is according to rates, both fixed and by volume of power, as approved by the Ontario Energy Board.

Pole rental revenues which is included in other operating revenue is according to rates per pole, as established by the Ontario Energy Board and is recognized as revenue as service is performed.

Late payment charges and interest income is recognized as revenue when earned.

Other miscellaneous income is recognized as service is performed.

Capital Contributions and Grants

Capital contributions are set up as a capital asset contra account, contributions and grants. This account is amortized on the same basis as the related capital assets.

Payment in Lieu of Taxes

The company accounts for payment in lieu of taxes using the liability payable method based on taxable income. Future income taxes arise from temporary differences in the accounting and tax basis of assets and liabilities. Future tax assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

Sioux Lookout Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2011

Basis of Accounting

Revenue and expenditures are reported on the accrual basis of accounting. The accrual basis of accounting recognizes revenues as they are earned and measurable; expenditures are the cost of goods and services acquired in the period whether or not payment has been made or invoices received.

Use of Estimates

The preparation of financial statements in accordance with accounting policies established for electric utilities in the Province of Ontario requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

The company utilizes various financial instruments. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of the financial instruments approximate their carrying values, unless otherwise noted.

All transactions related to financial instruments are recorded on a trade date basis.

Handbook Section 3862 establishes a fair value hierarchy which includes three levels of inputs that may be used to measure fair value.

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2 - Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or can be corroborated by observable market data for substantially the full term of the assets or liabilities; and
- Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

The company classifies its financial instruments into one of the following categories based on the purpose for which the asset was acquired. There were no transfers between Level 1 and 2 in the year. There were no investments classified as Level 2 or 3. The company's accounting policy for each category is as follows:

Held-for-Trading

This category is comprised of cash and bank (classified as Level 1). They are carried in the balance sheet at fair value with changes in fair value recognized in the statement of operations. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Financial Instruments (continued) Loans and Receivables

These assets are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date or dates or on demand. They arise principally through the provision of goods and services to customers (accounts receivable and unbilled revenue), but also incorporate other types of contractual monetary assets. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest method, less any provision for impairment. Transaction costs related to loans and receivables are expensed as incurred.

Other Financial Liabilities

Other financial liabilities includes all financial liabilities other than those classified as held-for-trading and comprise accounts payable and accrued liabilities, due to related parties, and bank borrowings. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are expensed as incurred.

Employee Future Benefits

The company provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province of Ontario for employees of municipalities, local boards, and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees contributory earnings. The company recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension provided by the company include the payments of the premiums on medical, dental and life insurance benefits, and accumulated sick leave credits. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expenses is recognized over the period from the entitlement date to the employees retirement date.

New Accounting Pronouncements

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date.

The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. At this time, the Corporation believes that the impact on its financial statements could be material.

On September 10, 2010, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board ("IASB") in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. Subsequently, the Canadian Securities Administrators announced that entities subject to rate regulation may defer the adoption of IFRS for up to one year, consistent with the one year deferral granted by the AcSB.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting ("RRA") standard under IFRS and the potential material impact of RRA on the Corporation's financial statements, the Corporation has decided to elect the optional one-year deferral of its adoption of IFRS. Accordingly, the Corporation will continue to prepare its financial statements in accordance with Canadian GAAP accounting standards in Part V of the CICA Handbook for 2011.

As a result of these developments related to IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Corporation cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operations. Although the Corporation has completed a detailed assessment of the accounting and disclosure differences between Canadian GAAP and IFRS, in light of the one-year deferral, this assessment will be revisited due to changes to standards during this period. The Corporation will continue to actively monitor IASB developments with respect to RRA and non-RRA IFRS developments and their potential impacts.

1. Inventory

	2011	2010
Balance, beginning of year	$ **44,830**	$ 52,707
Purchases	**123,925**	100,773
Sold to customer	**(4,254)**	-
Transfer to capital assets	**(102,842)**	(108,650)
Balance, end of year	$ **61,659**	$ 44,830

2. Due to Related Parties

At the end of the year the amounts due to related parties are as follows:

	2011	2010
Due to Shareholder:		
Corporation of the Municipality of Sioux Lookout	$ **250,000**	$ 212,956

These balances are unsecured, interest free, payable on demand and have arisen from the transfer of assets, dividends declared and provision of services referred to below.

There was a dividend declared and payable of $250,000 (2010 - $212,956). During the year the company billed electricity and services to the shareholder in the amount of $707,274 (2010 - $749,517).

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

December 31, 2011

3. Regulatory Assets (Liabilities)

Under Bill 210, certain costs and variance account balances are deemed to be "regulatory assets (liabilities)" in accordance with the OEB Accounting Procedures Handbook. These assets are to be reflected on the Corporation's balance sheet. The OEB has granted the Corporation permission to recover the regulatory assets when establishing its distribution rates.

	2011	2010
Retail settlement variances	$ 11,986	$ 13,471
Wholesale market service variances	(194,661)	(185,064)
Network charges variances	(11,891)	(4,281)
Connection charges variances	(6,364)	285,994
Power charges variances	(268,785)	(786,312)
Other regulatory assets	19,765	17,144
Smart meter rate adder funding	(198,908)	(114,667)
Smart meter deferral	843,996	762,066
Disposition and recovery of regulatory balances	(96,798)	196,384
	$ 98,340	$ 184,735

4. Property, plant and equipment

	2011		2010	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Buildings	$ 91,864	$ 41,022	$ 91,864	$ 37,347
Distribution system-overhead	4,553,456	1,661,162	4,388,392	1,479,023
Distribution system - underground	1,061,094	373,598	1,001,186	331,154
Distribution transformers	1,607,741	587,435	1,545,612	523,126
Distribution meters	454,082	126,508	447,604	114,629
Other equipment - various	806,831	652,138	774,590	617,002
Contributions and grants	(891,191)	(205,212)	(817,216)	(169,933)
Construction in progress	20,502	-	28,592	-
	$ 7,704,379	$ 3,236,651	$ 7,460,624	$ 2,932,348
Net book value		$ 4,467,728		$ 4,528,276

December 31, 2011

5. Bank Indebtedness

		2011		2010
Demand installment loan, repayable at $5,814 per month including interest at 4.7%, secured by a general security agreement covering all assets; due 2019	$	**661,830**	$	699,530
Demand installment loan, repayable at $15,500 per month plus interest at prime, secured by a general security agreement covering all assets; due 2022		**1,944,989**		2,130,990
	$	**2,606,819**	$	2,830,520

The demand installment loans are secured by a general security agreement covering all assets and are guaranteed by Corporation of the Municipality of Sioux Lookout.

The company has an unused operating line of credit of $175,000 with terms of due on demand and bears interest at the bank's prime rate calculated and payable monthly.

At December 31, 2011 the fair value of the bank indebtedness was $2,183,280 calculated based on the amount of future cash flows associated with each instrument discounted using 5% which is an estimate of what the company's current borrowing rate for similar debt instruments of comparable maturity would be.

The agreement governing the demand installment loan facility contains certain covenants regarding (i) debt servicing ratios, (ii) negative pledge where no lien can be assigned against assets, and (iii) the bank must approve any material change to the company.

6. Employee Benefits Payable

		2011		2010
Vacation pay	$	**33,495**	$	34,806
Vested sick leave		**43,292**		42,234
Banked overtime		**4,472**		2,498
Post employment benefits		**39,229**		45,988
	$	**120,488**	$	125,526

The post employment benefits is estimated based on the premiums paid to employees from date eligible to retire, until age 65. The estimate assumes an inflation rate of 3.46% and a discount rate of 4%.

December 31, 2011

7. Share Capital

The authorized class A preference share capital of the company is an unlimited number of non-voting shares, with a stated value equal to the consideration received on issue, redeemable and retractable at $1,000 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class B preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $100 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class C preference share capital of the company is an unlimited number of non-voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized class D preference share capital of the company is an unlimited number of voting shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The authorized common share capital of the company is an unlimited number of shares.

The issued share capital is as follows:

		2011	2010
100	Common shares	**$ 2,789,823**	$ 2,789,823

8. Financial Income and Expense

	2011	2010
Interest on assets held-for-trading	**$ 21,163**	$ 13,536
Interest expense on financial liabilities measured at amortized cost	**32,073**	30,521
Interest expense on financial assets measured at fair value	**112,800**	108,122
	144,873	138,643
Net finance costs	**$ (123,710)**	$ (125,107)

December 31, 2011

9. Other Operating Revenue

		2011		2010
Late payment charges	$	**38,119**	$	37,665
Interest income		**21,163**		13,536
Pole rentals		**43,194**		40,279
Change in occupancy charges		**16,560**		16,260
Sentinel light rental		**10,147**		9,838
Sundry		**3,846**		12,576
	$	**133,029**	$	130,154

10. Pension Agreement

The company makes contributions to the Ontario Municipal Employers Retirement Fund (OMERS), which is a multi-employer plan, on behalf of eight members of its staff. The plan is a deferred benefit plan which specifies the amount of the retirement benefit to be received by the employee based on the length of service and rate of pay.

During the year ended December 31, 2011 the Board contributed $50,233 (2010 - $42,407) to the plan. As this is a multi-employer pension plan, these contributions are the Board's pension benefit expenses. No pension liability for this type of plan is included in the Board's financial statements.

11. Supplementary Cash Flow Information

		2011		2010
Interest paid	$	**144,873**	$	138,643
Payment in lieu of taxes paid	$	**47,850**	$	52,304

December 31, 2011

12. Amortization of Property, plant and equipment

		2011		2010
Amortization of building and distribution equipment	$	**304,446**	$	300,774
Amortization of office equipment		**8,673**		8,009
Amortization of contributions and grants		**(35,278)**		(28,177)
		277,841		280,606
Amortization of other capital assets included in relevant expense categories				
Rolling stock		**14,790**		46,249
Operations and maintenance		**10,141**		15,353
Sentinel lights		**1,531**		2,344
	$	**304,303**	$	344,552

13. Commitments

The company has entered into an operating lease for certain equipment (Altec Aerial Device). The equipment is leased at $3,176 per month under a lease expiring in 2013.

The minimum annual lease payments for the next two years are as follows:

2012	$	38,112
2013	$	25,408

14. Fair Value of Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, and accounts payable and accrued liabilities approximate their carrying amounts because of the short-term maturity of these instruments.

The fair value of the due to related parties amount has not not been determined as disclosed in Note 2.

The fair value of bank indebtedness is disclosed in Note 5.

December 31, 2011

15. Financial Instrument Risk Exposure and Management

The Board has overall responsibility for the determination of the company's risk management objectives and policies while retaining ultimate responsibility for them. It has delegated the authority for designing and operating processes that ensure the effectiveness of the objectives and policies to the company's finance function. The Board receives quarterly financial reports from the manager through which it reviews the effectiveness of the processes put in place and the results of operations.

Credit Risk

The company has a policy it follows to ensure that the accounts receivables are collected on a timely basis. When a customer account goes into arrears Thunder Bay Hydro Inc. calls the customer in an effort to secure payment. In the event that the calls fail, Sioux Lookout Hydro Inc. will follow up with a letter that explains to the customer the ramifications of not paying their account. Once several days pass the services provided to the customer will be cut off. This process is followed unless the Board directs management to exclude certain customers groups from having their services cut off.

If a customer leaves their residence and the above collection process is not successful, Sioux Lookout Hydro Inc. will engage the services of a collection bureau to pursue these customer accounts. When an account is transferred to a collection bureau management sets these accounts up as doubtful accounts. At year end the allowance for doubtful accounts balance was $58,702 (2010 - $90,548). When all avenues to collect outstanding receivables have been exhausted management, with Board approval, will write off the receivables. During the year the company wrote off $ 35,849 of outstanding receivables (2010 - $nil).

Sioux Lookout Hydro Inc. is in the normal course of operations, exposed to credit risk from having bank account balances over the amounts insured by the Canadian Deposit Insurance Corporation. The interest rate on the bank account is prime less 2%.

Liquidity Risk

The company's policy is to ensure that it will always have sufficient cash to allow it to meet its liabilities when they become due. Management reconciles its bank on a monthly basis and it funds temporary cash shortages through a line of credit with the bank.

15. Financial Instrument Risk Exposure and Management (continued)

The following table illustrates the contractual maturity analysis of the company's financial liabilities. It is prepared on a gross basis and assumes the bank demand loan is repaid according to the installment schedule and prevailing interest rates (prime).

	2012	2013	2014	2015	2016	Thereafter	Total
Non-derivative financial instruments	$ 311,565	$ 305,985	$ 300,405	$ 294,825	$ 289,245	$ 1,628,457	$3,130,482

Market Risk

Market risk arises from the company's floating rate demand loan and fixed rate loans.

The annualised effect of a 1.0% decrease in the interest rate at the balance sheet date on the floating rate demand loan carried at that date would, all other variables held constant; have resulted in an increase in post-tax profit for the year of $31,500. A 1.0% increase in the interest rate would, on the same basis, have decreased post-tax profit by the same amount.

The annualised effect of a 1.0% decrease in the interest rate at the balance sheet on the fixed rate loan carried at that date would, all other variables held constant; have resulted in a decrease in the fair value of the loan of $44,000. A 1.0% increase in the interest rate would, on the same basis, have increased the fair value by the same amount.

16. Capital Disclosures

Sioux Lookout Hydro Inc. manages its capital in a manner consistent with the risk characteristics of the assets it holds. All financing, including equity and debt are analyzed by management and approved by the board of directors.

The company's objectives when managing capital are:

a) to safeguard the company's ability to continue as a going concern and provide returns for shareholders;

b) to maintain a safe and reliable electricity distribution system.

The company is meeting its objective of managing capital through its detailed review and preparing short-term and long-term cash flow analysis to ensure an adequate amount of liquidity and monthly review of financial results.

There have been no changes in the company's approach to capital management from the previous years.

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND REGULATORY ACCOUNTING:

The only reconciliation required between financial statements and regulatory accounting relate to those expenses which the OEB has disallowed for rate application purposes. These have identified in the table below. These expenses have been removed from requested OM&A expenses for 2013 Test Year in Exhibit 4 of this application.

Table 1.3 – Reconciliation from Audited OM&A Expense to Regulatory OM&A Expense

OM&A Reconciliation from Audited to Regulatory				
	2008	**2009**	**2010**	**2011**
OM&A as per Audited Financial Statements	**1,087,971**	**1,078,520**	**1,109,785**	**1,110,054**
Add: Bank Charges (Categorized: Interest in Audited, Billing and Collecting - OEB)	60,765	60,242	50,655	45,528
Add: Sentinel light amortization (Categorized : Amortization in Audited F/S, Maintenance - OEB)	2,328	2,509	2,343	1,531
Less: Miscellaneous credit (Categorized: Revenue in Audited F/S, Miscellaneous Admin - OEB)	-4,086	-1,210	-1,835	-1,949
Add: Special Purpose Charge Expense			12,498	15,042
OM&A Expense Before Removal of Non-Regulated Expenses	**1,146,978**	**1,140,061**	**1,173,446**	**1,170,206**
Less: Sentinel Light expenses	-3,199	-4899	-4438	-4533
Less: Special Purpose Charge Expenses			-12498	-15042
Regulatory OM&A Expenses	**1,143,779**	**1,135,162**	**1,156,510**	**1,150,631**

SLHI would also like to note that for 2008, 2009, 2010 and 2011, it had not adopted the half year rule for depreciation in the year of acquisition in its audited financial statements. In 2012, SLHI completed an adjusting entry that recorded the cumulative difference between actual depreciation expense for these four years and the amount that would have been recorded using the half year rule. This difference was booked to depreciation expense in 2012. As of 2012, SLHI has adopted the half year rule for depreciation in the year of acquisition. This is reflected in 2012 & 2013 amortization expense and related continuity schedules as found in Exhibit 2 and Exhibit 4.

PRO FORMA FINANCIAL STATEMENTS - 2012 AND 2013:

The Pro Forma Statements for the 2012 Bridge Year and the 2013 Test Year accompany this Schedule as Appendix E and Appendix F respectively.

APPENDIX E

COPY OF SIOUX LOOKOUT HYDRO INC.

2012 PRO FORMA FINANCIAL STATEMENTS – MCGAAP

Sioux Lookout Hydro Inc.
, License Number ED-2002-0514, File Number EB-2012-0165

Sioux Lookout Hydro Inc.
2012 PRO FORMA BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	440,422
1010-Cash Advances and Working Funds	0
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	628,343
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	0
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	163,435
1120-Accrued Utility Revenues	1,135,689
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(58,702)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	336,595
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**2,645,782**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	61,659
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**61,659**

1150-Non-Current Assets

1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	0
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**0**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	17,843
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	12,316
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	0
1550-LV Charges - Variance	17,221
1555-Smart Meters Recovery	181,592
1556-Smart Meters OM & A	0
1562-Deferred PILs	0
1563-Deferred PILs - Contra	0
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0

1576-Accounting Changes Under CGAAP	(98,888)
1580-RSVA - Wholesale Market Services	(84,441)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	1,755
1586-RSVA - Connection Charges	(15,952)
1588-RSVA - Commodity (Power)	(26,864)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	(317,934)
1200-Other Assets and Deferred Charges Total	**(313,352)**

1450-Distribution Plant	
1805-Land	0
1806-Land Rights	0
1808-Buildings and Fixtures	91,864
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	0
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	3,576,896
1835-Overhead Conductors and Devices	1,105,837
1840-Underground Conduit	178,392
1845-Underground Conductors and Devices	913,950
1850-Line Transformers	1,654,689
1855-Services	0
1860-Meters	810,996
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**8,332,624**

1500-General Plant	
1905-Land	0
1906-Land Rights	0
1908-Buildings and Fixtures	0
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	22,237
1920-Computer Equipment - Hardware	68,885
1925-Computer Software	81,285
1930-Transportation Equipment	526,979
1935-Stores Equipment	0

1940-Tools, Shop and Garage Equipment	90,141
1945-Measurement and Testing Equipment	12,694
1950-Power Operated Equipment	136,522
1955-Communication Equipment	37,334
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	29,688
1990-Other Tangible Property	0
1995-Contributions and Grants	(983,191)
1500-General Plant Total	**22,574**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	22,611
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**22,611**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(3,465,956)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(3,465,956)**

Total Assets	**7,305,941**

1650-Current Liabilities	
2205-Accounts Payable	1,765,850

2208-Customer Credit Balances	98,812
2210-Current Portion of Customer Deposits	13,754
2215-Dividends Declared	200,000
2220-Miscellaneous Current and Accrued Liabilities	37,967
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	45,464
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	227,570
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	5,898
2268-Accrued Interest on Long Term Debt	6,834
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	(90,373)
2292-Payroll Deductions / Expenses Payable	13,299
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	(15,111)
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**2,309,964**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	39,230
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	12,275
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	123,784
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	(136,243)
2405-Other Regulatory Liabilities	0

2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**39,046**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	2,150,360
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**2,150,360**

1850-Shareholders' Equity	
3005-Common Shares Issued	2,789,823
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	0
3046-Balance Transferred From Income	(17,930)
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	(200,000)
3055-Adjustment to Retained Earnings	234,679
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**2,806,572**

Total Liabilities & Shareholder's Equity	**7,305,942**

Balance Sheet Total	(0)

Sioux Lookout Hydro Inc.
, License Number ED-2002-0514, File Number EB-2012-0165

Sioux Lookout Hydro Inc.
2012 PRO FORMA STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	0
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	0
4030-Sentinel Energy Sales	(10,462)
4035-General Energy Sales	0
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	(390)
4055-Energy Sales for Resale	(6,350,558)
4060-Interdepartmental Energy Sales	0
4062-WMS	(500,095)
4064-Billed WMS-One Time	0
4066-NS	(404,649)
4068-CS	(93,492)
4075-LV Charges	(209,988)
3000-Sales of Electricity Total	**(7,569,634)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(2,051,444)
4080-2-SSS Revenue	(8,238)
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(2,059,682)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(42,027)
4215-Other Utility Operating Income	0

4220-Other Electric Revenues	0
4225-Late Payment Charges	(39,868)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(16,741)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(98,636)**
3150-Other Income & Deductions	
4305-Regulatory Debits	98,888
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	234
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(1,195)
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	0
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**97,927**
3200-Investment Income	
4405-Interest and Dividend Income	1,709
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**1,709**
3350-Power Supply Expenses	
4705-Power Purchased	6,350,558
4708-WMS	412,777

4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	404,649
4715-System Control and Load Dispatching	0
4716-NCN	93,492
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	87,318
4750-LV Charges	209,988
3350-Power Supply Expenses Total	**7,558,782**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	0
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	505,323
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	68,143
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	0
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	11,174
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**584,640**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	0

5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	0
5120-Maintenance of Poles, Towers and Fixtures	35,557
5125-Maintenance of Overhead Conductors and Devices	0
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	61,197
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	19,681
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	2,000
5172-Sentinel Lights - Materials and Expenses	2,709
5175-Maintenance of Meters	199,472
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**320,616**
3650-Billing and Collecting	
5305-Supervision	0
5310-Meter Reading Expense	4,763
5315-Customer Billing	178,262
5320-Collecting	94,777
5325-Collecting - Cash Over and Short	300
5330-Collection Charges	0
5335-Bad Debt Expense	20,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**298,102**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	0
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**0**
3800-Administrative and General Expenses	

5605-Executive Salaries and Expenses	23,820
5610-Management Salaries and Expenses	188,403
5615-General Administrative Salaries and Expenses	1,200
5620-Office Supplies and Expenses	11,902
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	23,971
5635-Property Insurance	18,480
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	55,782
5660-General Advertising Expenses	10,257
5665-Miscellaneous Expenses	33,493
5670-Rent	19,866
5675-Maintenance of General Plant	0
5680-Electrical Safety Authority Fees	2,501
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**389,675**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	318,369
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**318,369**
3900-Interest Expense	
6005-Interest on Long Term Debt	50,503
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	32,411

6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**82,914**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	4,986
3950-Taxes Other Than Income Taxes Total	**4,986**
4000-Income Taxes	
6110-Income Taxes	1,286
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**1,286**
4100-Extraordinary & Other Items	
6205-Donations	2,130
6210-Life Insurance	0
6215-Penalties	0
6210-Life Insurance	0
6310 - Extraordinary Deductions	84,746
4100-Extraordinary & Other Items Total	**86,876**
Net Income - (Gain)/Loss	**17,930**

APPENDIX F

COPY OF SIOUX LOOKOUT HYDRO INC.

2013 PRO FORMA STATEMENTS – MCGAAP (Existing Rates)

Sioux Lookout Hydro Inc.
, License Number ED-2002-0514, File Number EB-2012-0165

Sioux Lookout Hydro Inc.
2013 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	401,085
1010-Cash Advances and Working Funds	0
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	510,996
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	0
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	163,435
1120-Accrued Utility Revenues	1,136,079
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(58,702)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	296,026
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**2,448,919**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	61,659
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**61,659**

Account Description	Total
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0

1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	0
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**0**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	17,843
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	12,316
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	0
1550-LV Charges - Variance	17,221
1555-Smart Meters Recovery	181,592
1556-Smart Meters OM & A	0
1562-Deferred PILs	0
1563-Deferred PILs - Contra	0
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1576-Accounting Changes Under CGAAP	(74,166)
1580-RSVA - Wholesale Market Services	(84,441)
1582-RSVA - One-Time	0

1584-RSVA - Network Charges	1,755
1586-RSVA - Connection Charges	(15,952)
1588-RSVA - Commodity (Power)	(26,864)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	(317,934)
1200-Other Assets and Deferred Charges Total	**(288,630)**

1450-Distribution Plant	
1805-Land	0
1806-Land Rights	0
1808-Buildings and Fixtures	91,864
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	0
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	3,625,969
1835-Overhead Conductors and Devices	1,118,105
1840-Underground Conduit	183,392
1845-Underground Conductors and Devices	1,003,102
1850-Line Transformers	1,714,456
1855-Services	0
1860-Meters	812,676
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**8,549,564**

1500-General Plant	
1905-Land	0
1906-Land Rights	0
1908-Buildings and Fixtures	0
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	22,237
1920-Computer Equipment - Hardware	70,885
1925-Computer Software	82,285
1930-Transportation Equipment	526,979
1935-Stores Equipment	0
1940-Tools, Shop and Garage Equipment	95,141
1945-Measurement and Testing Equipment	19,694
1950-Power Operated Equipment	222,522
1955-Communication Equipment	37,334

1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	31,688
1990-Other Tangible Property	0
1995-Contributions and Grants	(1,075,191)
1500-General Plant Total	**33,574**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	22,611
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**22,611**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(3,721,831)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(3,721,831)**

Total Assets	**7,105,865**

1650-Current Liabilities	
2205-Accounts Payable	1,972,901
2208-Customer Credit Balances	98,812
2210-Current Portion of Customer Deposits	13,754
2215-Dividends Declared	221,970
2220-Miscellaneous Current and Accrued Liabilities	37,967
2225-Notes and Loans Payable	0

2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	45,464
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	229,567
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	5,898
2268-Accrued Interest on Long Term Debt	6,208
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	(90,373)
2292-Payroll Deductions / Expenses Payable	13,299
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	(15,111)
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**2,540,356**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	39,230
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	17,424
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	123,784
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	(136,243)
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**44,195**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	1,920,793
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**1,920,793**

1850-Shareholders' Equity	
3005-Common Shares Issued	2,789,823
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	0
3046-Balance Transferred From Income	98,496
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	(221,970)
3055-Adjustment to Retained Earnings	(65,828)
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**2,600,521**

Total Liabilities & Shareholder's Equity	**7,105,865**

Balance Sheet Total	0

Sioux Lookout Hydro Inc.
, License Number ED-2002-0514, File Number EB-2012-0165

Sioux Lookout Hydro Inc.
2013 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	0
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	0
4030-Sentinel Energy Sales	(10,462)
4035-General Energy Sales	0
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	(390)
4055-Energy Sales for Resale	(6,460,450)
4060-Interdepartmental Energy Sales	0
4062-WMS	(503,009)
4064-Billed WMS-One Time	0
4066-NS	(482,007)
4068-CS	(107,066)
4075-LV Charges	(250,381)
3000-Sales of Electricity Total	**(7,813,765)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(1,789,316)
4080-2-SSS Revenue	(8,265)
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(1,797,581)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(42,027)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0

4225-Late Payment Charges	(39,868)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(16,741)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(98,636)**
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(2,122)
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	0
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(2,122)**
3200-Investment Income	
4405-Interest and Dividend Income	(20,002)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(20,002)**
3350-Power Supply Expenses	
4705-Power Purchased	6,460,450
4708-WMS	415,182
4710-Cost of Power Adjustments	0
4712-0	0

4714-NW	482,007
4715-System Control and Load Dispatching	0
4716-NCN	107,066
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	87,827
4750-LV Charges	250,381
3350-Power Supply Expenses Total	**7,802,913**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	0
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	474,385
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	84,010
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	0
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	69,968
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**628,363**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	0
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	0

5120-Maintenance of Poles, Towers and Fixtures	48,730
5125-Maintenance of Overhead Conductors and Devices	0
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	61,200
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	13,774
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	2,000
5172-Sentinel Lights - Materials and Expenses	2,960
5175-Maintenance of Meters	72,941
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**201,605**
3650-Billing and Collecting	
5305-Supervision	0
5310-Meter Reading Expense	4,876
5315-Customer Billing	195,212
5320-Collecting	96,877
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	0
5335-Bad Debt Expense	20,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**316,965**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	0
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**0**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	15,144
5610-Management Salaries and Expenses	224,779
5615-General Administrative Salaries and Expenses	5,000
5620-Office Supplies and Expenses	7,103

5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	36,773
5635-Property Insurance	18,850
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	33,046
5660-General Advertising Expenses	1,061
5665-Miscellaneous Expenses	40,882
5670-Rent	19,866
5675-Maintenance of General Plant	0
5680-Electrical Safety Authority Fees	2,501
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**405,005**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	180,404
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**180,404**
3900-Interest Expense	
6005-Interest on Long Term Debt	45,388
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	30,802
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**76,190**

3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	4,986
3950-Taxes Other Than Income Taxes Total	**4,986**
4000-Income Taxes	
6110-Income Taxes	14,724
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**14,724**
4100-Extraordinary & Other Items	
6205-Donations	2,455
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**2,455**
Net Income - (Gain)/Loss	**(98,496)**

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

No reconciliation is required between the 2013 Pro Forma statement and the revenue deficiency statement.

INFORMATION ON AFFILIATES:

Sioux Lookout Hydro Inc. has no affiliated companies. It is wholly owned by the Municipality of Sioux Lookout.

MATERIALITY THRESHOLDS:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the Board June 28, 2012 states the relevant default materiality threshold as:

“$50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million.”

Therefore SLHI will analyze all variances greater than $50,000 in its application.

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
	1			**Overview**
		1		Overview
		2		Variance Analysis of Rate Base
	2			**Gross Assets – Property, Plant and Equipment Accumulated Amortization**
		1		Continuity Statements
		2		Gross Assets Table
		3		Variance Analysis on Gross Assets
		4		Accumulated Amortization Table
		5		Variance Analysis on Accumulated Amortization
	3			**Capital Budget**
		1		Introduction
		2		Assignment of Capital Projects to USoA
		3		Asset Management Plan Summary
		4		Capitalization Policy
		5		Service Quality & Reliability Performance
	4			**Allowance for Working Capital**
		1		Overview and Calculation by Account
	5			**Summary of Changes "Modified" CGAAP**
			1	Summary of Changes as a Result of Modifying Capitalization and Depreciation Policy "Modified" CGAAP (MCGAAP)
			2	Impact on Fixed Assets

Exhibit	Tab	Schedule	Appendix	Contents
			3	Impact on Capitalization of Burdens
			4	Impact on Rate Base
	6			**Green Energy Plan**
		1		Funding Adder
Appendices			2-A	Asset Management Plan
			2-B	Green Energy Plan
			2-C	OPA Letter of Comment
			2-D	Service Quality & Reliability Performance (2008 to 2011)

OVERVIEW

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2013 Test Year, plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. Sioux Lookout Hydro Inc.'s rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

SLHI has provided its rate base calculations for the years 2008 OEB Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year in Table 1.1 below. As noted throughout this application, SLHI has modified its capitalization and depreciation policies to align with APH guidelines regarding MIFRS. SLHI has calculated its 2013 rate base as $6,106,606 under MCGAAP which will be used to determine the proposed revenue requirement.

Table 1.1: Summary of Rate Base

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MCGAAP)	2013 Test (MCGAAP)
Average Net Book Value of FA	4,777,273	4,615,526	4,596,857	4,546,439	4,495,618	4,631,767	4,684,949	4,890,153
Working Capital Allowance%	15%	15%	15%	15%	15%	13%	13%	13%
Working Capital Allowance	1,434,981	1,006,106	695,696	954,499	1,095,922	1,183,913	1,190,384	1,216,453
Rate Base	**6,212,254**	**5,621,632**	**5,292,553**	**5,500,938**	**5,591,540**	**5,815,680**	**5,875,333**	**6,106,606**

The SLHI Distribution System:

Sioux Lookout Hydro Inc. owns and operates the electricity distribution system in its licensed service area in the Corporation of the Municipality of Sioux Lookout serving approximately 2,757 Residential, General Service, Street Light, and Unmetered Scattered Load customers/connections.

SLHI is comprised of 6 square kilometres of high density urban area plus 530 square kilometres of low density rural for a total of 536 square kilometres. SLHI's population density (customers per square kilometre) is 5.14 which makes it one of the 5 LDCs in the province with a population density of less than 10 customers per square kilometre (as per the 2011 OEB Yearbook of Electricity Distributors). SLHI faces unique challenges inherent with this type of service area. SLHI is also embedded in Hydro One territory as they serve the outlying customers beyond the Municipal Boundaries and Lac Seul Reservation.

The SLHI system was primarily rebuilt in the 1980's and 1990's. The rebuild upgraded the voltage of the system from 4.16 kV to 14.4 kV.

Some key system statistics are as follows:

# of Poles	2927
# of Distribution Transformers	854
Km of Overhead Line	248
Km of Underground Line	36

In managing its distribution system assets, SLHI's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service expectations. This Application incorporates SLHI's 2013 Capital and Expense

Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

SLHI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, system configuration, line loss reduction, outage mitigation and procuring the lowest cost of commodity to determine investment needs in the system.

On an annual basis, SLHI reviews capital projects identified for potential implementation and prioritizes each project based on defined criteria basis. All members of the management team follow these criteria as they individually complete outlines of their recommendations, which are then discussed by the full management team. After examining all recommended projects, each are listed in order from high to low priority and then moved forward based on as an "as-needed" basis.

Various studies and assessments of SLHI assets are used to determine project priorities. For example SLHI uses a database of pole location, type, age, and condition to provide a basis for long-range pole replacement plans. In addition, priorities may be affected by outside regulatory requirements as with an obligation to relocate a pole line to accommodate a municipal road widening.

In addition to the capital needs of the network, SLHI provides and plans for system maintenance of the network on a priority basis. The same preparation and consideration steps are undertaken before the final recommended budget amounts are established. Further information on SLHI's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

Capital Asset Categories

SLHI's assets fall into two broad categories – The first is ***distribution plant***, which includes assets such as poles, conductor, overhead and underground electricity distribution infrastructure, transformers, and meters. The second is ***general plant*** which includes assets such as:

maintenance building; office furniture; transportation equipment; communications technology; computer equipment and software; general equipment; and tools. A more detailed list of distribution and general plant categories can be found in Table 2.9 (Gross Assets) in Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects:

SLHI's capital budget items include:

- **Customer Demand:**

These are projects that SLHI undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and SLHI's Conditions of Service. Activities include connecting new customers and building or overseeing construction of distribution systems for new subdivisions. Capital contributions toward the cost of these projects are collected by SLHI in accordance with the DSC and the provisions of its Conditions of Service. These contributions are included in the annual capital budgets.

- **Renewal:**

Renewal projects are completed when assets reach the end of their useful life and must be replaced. SLHI completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Capacity:**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects. These projects benefit many customers.

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve SLHI reliability performance as measured by: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). These measures are indicators of the reliability of SLHI's distribution system. These activities will support maintenance of, or improvement to, the Service Quality Indices measured and submitted to the OEB each year by SLHI. The Asset Management Plan summary provided in Exhibit 2, Tab 3, Schedule 3 and the Asset Management Plan provided in Appendix 2-A, support the capital and maintenance programs needed to maintain and enhance the reliability of SLHI's distribution system.

- **Regulatory Requirements:**

These projects are system capital investments which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment and the Municipality of Sioux Lookout. Regulatory requirement projects can also include relocating system plant for roadway reconstruction work. Where road widening projects are required as a result of municipal infrastructure development, SLHI follows the *Public Service Works on Highways Act, 1990* and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of SLHI labour and vehicles.

- **Transformer Stations:**

SLHI does not own any transformer stations.

- **Substations:**

SLHI does not own any distribution substations.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. In 2009 SLHI began installation of smart meters and completed the program in 2011.

SLHI capital projects for the 2013 Test Year are discussed in further detail in Exhibit 2, Tab 3, Schedule 2. SLHI has provided project-specific justifications for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year.

Gross Assets – Property, Plant and Equipment and Accumulated Amortization:

The 2012 Bridge and 2013 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. Analyses of 2008 to 2013 capital programs are described in detail in SLHI's written evidence at Exhibit 2, Tab 3, Schedule 2.

Budget Process:

SLHI's Asset Management Plan, which sets out processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers, accompanies this Exhibit as Appendix 2-A.

The budget is prepared annually by management and is reviewed and approved by the SLHI Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it typically does not change but provides a plan against which actual results may be evaluated.

The SLHI Board has on occasion directed Management to revise a Budget following consideration of year-end financial results or major changes in capital job priorities.

Responsibilities:

- It is the responsibility of the Finance department to co-ordinate the development of the operating budget, capital budget and forecast processes.
- Each department is responsible for preparing its respective operating budget, capital budget, and forecasts.
- The Operations Manager (or designate) is responsible for the capital budget.
- The President/CEO is responsible for presenting and recommending the budget to the Board of Directors for approval.

The budget is an important planning tool for SLHI. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of departmental budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. SLHI notes that these Budget Plans address both capital and operating requirements.

VARIANCE ANALYSIS OF RATE BASE

The following tables exclude amounts for Sentinel Lights, which are not included in the rate base.

Table 1.2: 2008 Approved Rate Base vs. 2008 Actual Rate Base

	2008 Board Approved	2008 Actual	Variance
Gross Fixed Assets	7,012,355	6,875,936	-136,419
Accumulated Depreciation	2,229,218	2,249,389	20,171
Net Book Value	4,783,137	4,626,547	-156,590
Average Net Book Value	4,777,273	4,615,526	-161,747
Working Capital Expenses	9,566,540	6,707,371	-2,859,169
Working Capital Allowance (15%)	1,434,981	1,006,106	-428,875
Rate Base	6,212,254	5,621,632	-590,622

The 2008 Approved Gross Fixed Assets and Accumulated Amortization amounts differ due to the following reasons.

The Gross fixed assets shows a variance of $(136,419) due primarily to a combination of lower actual 2007 expenditures by $32,000, the postponement of the Mill Line upgrade due to the closure of the Pulp Mill ($79,410 budgeted) and the actual cost of the budgeted 2008 truck replacement. (budgeted $80,000, actual $68,000).

The Accumulated Depreciation variance of $20,171 is due to not writing off stranded meter assets in 2008, and not applying the ½ year rule for depreciation until 2012.

The 2008 actual rate base was $590,622 lower than approved by the Board. $428,875 of this amount was due to lower working capital expenses than anticipated. The main reason for this is the decrease in the Cost of Power Expenses. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1. The remaining $161,747 is primarily the result of SLHI under spending on budgeted capital projects for 2007 and 2008. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2.

Table 1.3: 2008 Actual Rate Base vs. 2009 Actual Rate Base			
	2008 Actual	**2009 Actual**	**Variance**
Gross Fixed Assets	6,875,936	7,138,420	262,484
Accumulated Depreciation	2,249,389	2,571,253	321,864
Net Book Value	4,626,547	4,567,167	-59,380
Average Net Book Value	4,615,526	4,596,857	-18,669
Working Capital Expenses	6,707,371	4,637,974	-2,069,397
Working Capital Allowance (15%)	1,006,106	695,696	-310,410
Rate Base	5,621,632	5,292,553	-329,079

The rate base of $5,292,553 for 2009 decreased by $329,079. This decrease is primarily the result of a decrease in the Cost of Power Expenses of $2,062,479. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2.

Table 1.4: 2009 Actual Rate Base vs. 2010 Actual Rate Base			
	2009 Actual	**2010 Actual**	**Variance**
Gross Fixed Assets	7,138,420	7,434,105	295,685
Accumulated Depreciation	2,571,253	2,908,394	337,141
Net Book Value	4,567,167	4,525,711	-41,456
Average Net Book Value	4,596,857	4,546,439	-50,418
Working Capital Expenses	4,637,974	6,363,324	1,725,350
Working Capital Allowance (15%)	695,696	954,499	258,803
Rate Base	5,292,553	5,500,938	208,385

The rate base of $5,500,938 for 2010 was an increase of $208,385. This increase is primarily the result of an increase in the Cost of Power Expenses from 2009 to 2010 of $1,725,350. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2.

Table 1.5: 2010 Actual Rate Base vs. 2011 Actual Rate Base

	2010 Actual	2011 Actual	Variance
Gross Fixed Assets	7,434,105	7,676,690	242,585
Accumulated Depreciation	2,908,394	3,211,166	302,772
Net Book Value	4,525,711	4,465,524	-60,187
Average Net Book Value	4,546,439	4,495,618	-50,821
Working Capital Expenses	6,363,324	7,306,144	942,820
Working Capital Allowance (15%)	954,499	1,095,922	141,423
Rate Base	5,500,938	5,591,540	90,602

In 2011, rate base increased by $90,602 from 2010. The 2011 working capital allowance increased by $141,423 from 2010 due primarily to the increase in the Cost of Power expenses. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2.

Table 1.6: 2011 Actual Rate Base vs. 2012 Bridge (MCGAAP) Rate Base

	2011 Actual	2012 Bridge (MCGAAP)	Variance	2011 Actual	2012 Bridge (CGAAP)	Variance	2012 Bridge (MCGAAP)	2012 Bridge (CGAAP)	Variance
Gross Fixed Assets	7,676,690	8,348,121	671,431	7,676,690	8,359,620	682,930	8,348,121	8,359,620	11,499
Accumulated Depreciation	3,211,166	3,443,746	232,580	3,211,166	3,561,611	350,445	3,443,746	3,561,611	117,865
Net Book Value	4,465,524	4,904,375	438,851	4,465,524	4,798,009	332,485	4,904,375	4,798,009	-106,366
Average Net Book Value	4,495,618	4,684,949	189,331	4,495,618	4,631,767	136,149	4,684,949	4,631,767	-53,182
Working Capital Expenses	7,306,144	9,156,801	1,850,657	7,306,144	9,107,026	1,800,882	9,156,801	9,107,026	-49,775
Working Capital Allowance (15%-2011, 13%-2012)	1,095,922	1,190,384	94,462	1,095,922	1,183,913	87,991	1,190,384	1,183,913	-6,471
Rate Base	5,591,540	5,875,333	283,793	5,591,540	5,815,680	224,140	5,875,333	5,815,680	-59,653

Table 1.6 illustrates the variance from 2011 actual compared to the 2012 Bridge year using CGAAP and MCGAAP. As discussed earlier, SLHI adopted a new capitalization policy in 2012. This policy is provided in Exhibit 2, Tab 3, Schedule 4. The table also illustrates the variance from 2012 Bridge (MCGAAP) compared to 2012 Bridge (CGAAP).

The 2012 Bridge Year includes the addition of smart meters to fixed assets, less the removal of stranded assets (meters) totaling $433,787. Accumulated amortization increased $136,674 related to smart meters, offset by $112,869 with the removal of the stranded assets.

The increase in Working Capital expenses of $1,850,657 is due to a combination of the recognition of smart meter expenses, increase in the Cost of Power, regulatory expenses and organizational restructuring which is further explained in Exhibit 4, Tab 2, Schedule 3.

Table 1.7: 2012 Bridge (MCGAAP) Rate Base vs. 2013 Test Year Rate Base

	2012 Bridge (MCGAAP)	2013 Test	Variance
Gross Fixed Assets	8,348,121	8,574,061	225,940
Accumulated Depreciation	3,443,746	3,698,130	254,384
Net Book Value	4,904,375	4,875,931	-28,445
Average Net Book Value	4,684,949	4,890,153	205,204
Working Capital Expenses	9,156,801	9,357,332	200,531
Working Capital Allowance 13%	1,190,384	1,216,453	26,069
Rate Base	5,875,333	6,106,606	231,273

The rate base increased by $231,273 for 2013. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2.

Overall rate base is projected to increase from 2008 actual by $484,975, but decrease from 2008 Board Approved by $105,648. This is due to less than budgeted for capital spending offset by increased working capital expenses.

A summary of SLHI's cost of power and controllable expenses used in the calculation of the working capital for the 2008 Board Approved, 2008 Actual to 2011 Actual, the 2012 Bridge Year and the 2013 Test Year is shown Exhibit 2, Tab 4, Schedule 1, Table 2.40.

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT and ACCUMULATED AMORTIZATION:

Fixed asset continuity schedules for 2008 to 2012 CGAAP, 2012 MCGAAP and 2013 MCGAAP are outlined in Tables 2.1 to 2.7 below. Please note that in the final total for Net Book Value, Sentinel Lights were subtracted so as not to be included in the rate base.

Table 2.1: Fixed Asset Continuity Schedule - 2008

Year 2008

				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)		$ 2,090	$ 2,160		$ 4,250	$ 418	$ 850		$ 1,268	$ 2,982
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land					$ -				$ -	$ -
47	1808	Buildings		$ 91,864			$ 91,864	$ 26,324	$ 3,675		$ 29,999	$ 61,865
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		$ 2,779,548	$ 157,373		$ 2,936,921	$ 673,135	$ 117,477		$ 790,612	$ 2,146,309
47	1835	Overhead Conductors & Devices		$ 1,079,172			$ 1,079,172	$ 302,157	$ 43,167		$ 345,324	$ 733,848
47	1840	Underground Conduit		$ 155,512	$ 7,589		$ 163,101	$ 41,322	$ 6,524		$ 47,846	$ 115,255
47	1845	Underground Conductors & Devices		$ 716,556	$ 54,030		$ 770,586	$ 173,573	$ 30,823		$ 204,396	$ 566,190
47	1850	Line Transformers		$ 1,336,479	$ 133,674		$ 1,470,153	$ 343,426	$ 58,806		$ 402,232	$ 1,067,921
47	1855	Services (Overhead & Underground)					$ -				$ -	$ -
47	1860	Meters		$ 318,716	$ 2,047	-$ 415	$ 320,348	$ 73,674	$ 13,566	-$ 166	$ 87,074	$ 233,274
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land					$ -				$ -	$ -
47	1908	Buildings & Fixtures					$ -				$ -	$ -
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 7,801	$ 1,652	-$ 734	$ 8,719	$ 4,294	$ 906	-$ 587	$ 4,613	$ 4,106
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
10	1920	Computer Equipment - Hardware					$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 11,997	$ 1,753		$ 13,750	$ 10,727	$ 1,324		$ 12,051	$ 1,699
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -				$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 306,152	$ 68,430	-$ 27,036	$ 347,546	$ 214,173	$ 42,482	-$ 25,346	$ 231,309	$ 116,237
10	1930	Transportation Equipment(5 years)		$ 59,134			$ 59,134	$ 32,441	$ 11,827		$ 44,268	$ 14,866
8	1940	Tools, Shop & Garage Equipment		$ 52,484	$ 6,177		$ 58,661	$ 29,138	$ 5,866		$ 35,004	$ 23,657
8	1945	Measurement & Testing Equipment		$ 12,188	$ 873		$ 13,061	$ 4,475	$ 1,306		$ 5,781	$ 7,280
8	1950	Power Operated Equipment		$ 108,187	$ 1,690	-$ 1,690	$ 108,187	$ 94,656	$ 5,171		$ 99,827	$ 8,360
8	1955	Communications Equipment		$ 33,911	$ 1,268		$ 35,179	$ 17,688	$ 3,678		$ 21,366	$ 13,813
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		$ 21,876	$ 1,408		$ 23,284	$ 12,266	$ 2,328		$ 14,594	$ 8,690
47	1995	Contributions & Grants		-$ 524,528	-$ 83,680		-$ 608,208	-$ 89,251	-$ 24,328		-$ 113,579	-$ 494,629
WIP		Work In Progress			$ 3,512		$ 3,512				$ -	$ 3,512
		Total		**$ 6,569,139**	**$ 359,956**	**-$ 29,875**	**$ 6,899,220**	**$ 1,964,635**	**$ 325,448**	**-$ 26,099**	**$ 2,263,984**	**$ 4,626,546**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 47,653
Tools/Sentinel Lights	$ 13,178
Net Depreciation	$ 264,617

Table 2.2: Fixed Asset Continuity Schedule - 2009

Year **2009**

				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)		$ 4,250			$ 4,250	$ 1,268	$ 850		$ 2,118	$ 2,132
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 91,864			$ 91,864	$ 29,999	$ 3,675		$ 33,674	$ 58,190
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		$ 2,936,921	$ 172,714		$ 3,109,635	$ 790,612	$ 124,385		$ 914,997	$ 2,194,638
47	1835	Overhead Conductors & Devices		$ 1,079,172			$ 1,079,172	$ 345,324	$ 43,167		$ 388,491	$ 690,681
47	1840	Underground Conduit		$ 163,101	$ 2,608		$ 165,709	$ 47,846	$ 6,628		$ 54,474	$ 111,235
47	1845	Underground Conductors & Devices		$ 770,586	$ 35,314		$ 805,900	$ 204,396	$ 32,236		$ 236,632	$ 569,268
47	1850	Line Transformers		$ 1,470,153	$ 6,590		$ 1,476,743	$ 402,232	$ 59,070		$ 461,302	$ 1,015,441
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 320,348	$ 95,936	-$ 25,887	$ 390,397	$ 87,074	$ 17,403	-$ 9,539	$ 94,938	$ 295,459
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 8,719	$ 4,659		$ 13,378	$ 4,613	$ 1,293		$ 5,906	$ 7,472
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 13,750	$ 25,810		$ 39,560	$ 12,051	$ 6,016		$ 18,067	$ 21,493
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 347,546			$ 347,546	$ 231,309	$ 39,068		$ 270,377	$ 77,169
10	1930	Transportation Equipment(5 years)		$ 59,134	$ 31,183		$ 90,317	$ 44,268	$ 9,062		$ 53,330	$ 36,987
8	1940	Tools, Shop & Garage Equipment		$ 58,661	$ 4,984		$ 63,645	$ 35,004	$ 6,364		$ 41,368	$ 22,277
8	1945	Measurement & Testing Equipment		$ 13,061		-$ 367	$ 12,694	$ 5,781	$ 1,267	-$ 39	$ 7,009	$ 5,685
8	1950	Power Operated Equipment		$ 108,187	$ 4,215		$ 112,402	$ 99,827	$ 5,241		$ 105,068	$ 7,334
8	1955	Communications Equipment		$ 35,179	$ 2,155		$ 37,334	$ 21,366	$ 3,894		$ 25,260	$ 12,074
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		$ 23,284	$ 1,810		$ 25,094	$ 14,594	$ 2,509		$ 17,103	$ 7,991
47	1995	Contributions & Grants		-$ 608,208	-$ 96,209		-$ 704,417	-$ 113,579	-$ 28,177		-$ 141,756	-$ 562,661
WIP		Work In Progress		$ 3,512	-$ 1,221		$ 2,291	$ -			$ -	$ 2,291
		Total		**$ 6,899,220**	**$ 290,548**	**-$ 26,254**	**$ 7,163,514**	**$ 2,263,984**	**$ 333,951**	**-$ 9,578**	**$ 2,588,357**	**$ 4,567,166**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 44,309
Tools/Sentinel Lights	$ 14,034
Net Depreciation	$ 275,608

Table 2.3: Fixed Asset Continuity Schedule – 2010

Year **2010**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 4,250	$ 2,295		$ 6,545	$ 2,118	$ 1,003		$ 3,121	$ 3,424
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 91,864			$ 91,864	$ 33,674	$ 3,675		$ 37,349	$ 54,515
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		$ 3,109,635	$ 198,775		$ 3,308,410	$ 914,997	$ 132,336		$ 1,047,333	$ 2,261,077
47	1835	Overhead Conductors & Devices		$ 1,079,172	$ 810		$ 1,079,982	$ 388,491	$ 43,199		$ 431,690	$ 648,292
47	1840	Underground Conduit		$ 165,709	$ 1,739		$ 167,448	$ 54,474	$ 6,698		$ 61,172	$ 106,276
47	1845	Underground Conductors & Devices		$ 805,900	$ 27,838		$ 833,738	$ 236,632	$ 33,350		$ 269,982	$ 563,756
47	1850	Line Transformers		$ 1,476,743	$ 68,869		$ 1,545,612	$ 461,302	$ 61,824		$ 523,126	$ 1,022,486
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 390,397	$ 57,207		$ 447,604	$ 94,938	$ 19,692		$ 114,630	$ 332,974
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 13,378	$ 356		$ 13,734	$ 5,906	$ 1,266		$ 7,172	$ 6,562
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 39,560	$ 320	-$ 556	$ 39,324	$ 18,067	$ 5,740	-$ 556	$ 23,251	$ 16,073
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 347,546			$ 347,546	$ 270,377	$ 33,688		$ 304,065	$ 43,481
10	1930	Transportation Equipment(5 years)		$ 90,317			$ 90,317	$ 53,330	$ 12,561		$ 65,891	$ 24,426
8	1940	Tools, Shop & Garage Equipment		$ 63,645	$ 1,130		$ 64,775	$ 41,368	$ 6,300		$ 47,668	$ 17,107
8	1945	Measurement & Testing Equipment		$ 12,694			$ 12,694	$ 7,009	$ 1,267		$ 8,276	$ 4,418
8	1950	Power Operated Equipment		$ 112,402	$ 23,400		$ 135,802	$ 105,068	$ 4,267		$ 109,335	$ 26,467
8	1955	Communications Equipment		$ 37,334			$ 37,334	$ 25,260	$ 3,519		$ 28,779	$ 8,555
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		$ 25,094	$ 1,425		$ 26,519	$ 17,103	$ 2,343		$ 19,446	$ 7,073
47	1995	Contributions & Grants		-$ 704,417	-$ 112,799		-$ 817,216	-$ 141,756	-$ 32,688		-$ 174,444	-$ 642,772
WIP		Work In Progress		$ 2,291	$ 26,301		$ 28,592	$ -			$ -	$ 28,592
		Total		**$ 7,163,514**	**$ 297,666**	**-$ 556**	**$ 7,460,624**	**$ 2,588,357**	**$ 340,040**	**-$ 556**	**$ 2,927,841**	**$ 4,525,710**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 37,955
Tools/Sentinel Lights	$ 13,429
Net Depreciation	$ 288,656

Table 2.4: Fixed Asset Continuity Schedule – 2011

Year **2011**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 6,545	$ 22,500		$ 29,045	$ 3,121	$ 1,684		$ 4,805	$ 24,240
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 91,864			$ 91,864	$ 37,349	$ 3,675		$ 41,024	$ 50,840
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		$ 3,308,410	$ 165,064		$ 3,473,474	$ 1,047,333	$ 138,939		$ 1,186,272	$ 2,287,202
47	1835	Overhead Conductors & Devices		$ 1,079,982			$ 1,079,982	$ 431,690	$ 43,199		$ 474,889	$ 605,093
47	1840	Underground Conduit		$ 167,448	$ 5,944		$ 173,392	$ 61,172	$ 6,936		$ 68,108	$ 105,284
47	1845	Underground Conductors & Devices		$ 833,738	$ 53,964		$ 887,702	$ 269,982	$ 35,508		$ 305,490	$ 582,212
47	1850	Line Transformers		$ 1,545,612	$ 62,129		$ 1,607,741	$ 523,126	$ 64,310		$ 587,436	$ 1,020,305
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 447,604	$ 6,478		$ 454,082	$ 114,630	$ 11,880		$ 126,510	$ 327,572
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 13,734	$ 3,798		$ 17,532	$ 7,172	$ 1,257		$ 8,429	$ 9,103
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 39,324	$ 2,337		$ 41,661	$ 23,251	$ 5,732		$ 28,983	$ 12,678
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 347,546			$ 347,546	$ 304,065	$ 8,554		$ 312,619	$ 34,927
10	1930	Transportation Equipment(5 years)		$ 90,317			$ 90,317	$ 65,891	$ 6,237		$ 72,128	$ 18,189
8	1940	Tools, Shop & Garage Equipment		$ 64,775	$ 2,436		$ 67,211	$ 47,668	$ 3,590		$ 51,258	$ 15,953
8	1945	Measurement & Testing Equipment		$ 12,694			$ 12,694	$ 8,276	$ 1,198		$ 9,474	$ 3,220
8	1950	Power Operated Equipment		$ 135,802			$ 135,802	$ 109,335	$ 3,778		$ 113,113	$ 22,689
8	1955	Communications Equipment		$ 37,334			$ 37,334	$ 28,779	$ 1,575		$ 30,354	$ 6,980
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		$ 26,519	$ 1,169		$ 27,688	$ 19,446	$ 1,531		$ 20,977	$ 6,711
47	1995	Contributions & Grants		-$ 817,216	-$ 73,975		-$ 891,191	-$ 174,444	-$ 35,279		-$ 209,723	-$ 681,468
WIP		Work In Progress		$ 28,592	-$ 8,090		$ 20,502	$ -			$ -	$ 20,502
		Total		**$ 7,460,624**	**$ 243,754**	**$ -**	**$ 7,704,378**	**$ 2,927,841**	**$ 304,304**	**$ -**	**$ 3,232,145**	**$ 4,465,522**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 12,332
Tools/Sentinel Lights	$ 7,894
Net Depreciation	$ 284,078

Table 2.5: Fixed Asset Continuity Statement – 2012 (CGAAP)

Year 2012 - Bridge

				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	$ 52,240		$ 81,285	$ 4,805	$ 39,701		$ 44,506	$ 36,779
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	$ 133,834		$ 3,607,308	$ 1,186,272	$ 127,737		$ 1,314,009	$ 2,293,299
47	1835	Overhead Conductors & Devices		$ 1,079,982	$ 25,855		$ 1,105,837	$ 474,889	$ 43,700		$ 518,589	$ 587,248
47	1840	Underground Conduit		$ 173,392	$ 6,200		$ 179,592	$ 68,108	$ 6,702		$ 74,810	$ 104,782
47	1845	Underground Conductors & Devices		$ 887,702	$ 35,823		$ 923,525	$ 305,490	$ 32,802		$ 338,292	$ 585,233
47	1850	Line Transformers		$ 1,607,741	$ 46,948		$ 1,654,689	$ 587,436	$ 59,823		$ 647,259	$ 1,007,430
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 454,082	$ 3,890	-$ 294,462	$ 163,510	$ 126,510	$ 11,733	-$ 112,869	$ 25,374	$ 138,136
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	-$ 1,295	$ 22,237	$ 8,429	$ 1,611	-$ 1,295	$ 8,745	$ 13,492
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	$ 13,823	-$ 1,519	$ 41,287	$ 27,598
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 347,546	$ 89,116		$ 436,662	$ 312,619	$ 9,482		$ 322,101	$ 114,561
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	$ 22,930		$ 90,141	$ 51,258	$ 7,702		$ 58,960	$ 31,181
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			$ 37,334	$ 30,354	$ 1,534		$ 31,888	$ 5,446
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	$ 2,000		$ 29,688	$ 20,977	$ 1,233		$ 22,210	$ 7,478
47	1995	Contributions & Grants		-$ 891,191	-$ 92,000		-$ 983,191	-$ 209,723	-$ 30,523		-$ 240,246	-$ 742,945
WIP		Work In Progress		$ 20,502	$ 2,109		$ 22,611	$ -			$ -	$ 22,611
		Total		**$ 7,704,378**	**$ 1,012,128**	**-$ 297,510**	**$ 8,418,996**	**$ 3,232,145**	**$ 489,572**	**-$ 115,683**	**$ 3,606,034**	**$ 4,805,484**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 13,334
Tools/Sentinel Lights	$ 11,556
Net Depreciation	$ 464,682

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

Year 2012 -Bridge

				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	$ 52,240		$ 81,285	$ 4,805	$ 39,701		$ 44,506	$ 36,779
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	$ 103,422		$ 3,576,896	$ 1,186,272	$ 54,541		$ 1,240,813	$ 2,336,083
47	1835	Overhead Conductors & Devices		$ 1,079,982	$ 25,855		$ 1,105,837	$ 474,889	$ 18,068		$ 492,957	$ 612,880
47	1840	Underground Conduit		$ 173,392	$ 5,000		$ 178,392	$ 68,108	$ 2,392		$ 70,500	$ 107,892
47	1845	Underground Conductors & Devices		$ 887,702	$ 26,248		$ 913,950	$ 305,490	$ 16,981		$ 322,471	$ 591,479
47	1850	Line Transformers		$ 1,607,741	$ 46,948		$ 1,654,689	$ 587,436	$ 30,345		$ 617,781	$ 1,036,908
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 454,082	$ 3,890	-$ 294,462	$ 163,510	$ 126,510	$ 11,733	-$ 112,869	$ 25,374	$ 138,136
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	-$ 1,295	$ 22,237	$ 8,429	$ 1,611	-$ 1,295	$ 8,745	$ 13,492
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	$ 13,823	-$ 1,519	$ 41,287	$ 27,598
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 347,546	$ 89,116		$ 436,662	$ 312,619	$ 9,482		$ 322,101	$ 114,561
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	$ 22,930		$ 90,141	$ 51,258	$ 7,702		$ 58,960	$ 31,181
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			$ 37,334	$ 30,354	$ 1,534		$ 31,888	$ 5,446
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	$ 2,000		$ 29,688	$ 20,977	$ 1,233		$ 22,210	$ 7,478
47	1995	Contributions & Grants		-$ 891,191	-$ 92,000		-$ 983,191	-$ 209,723	-$ 22,161		-$ 231,884	-$ 751,307
WIP		Work In Progress		$ 20,502	$ 2,109		$ 22,611	$ -			$ -	$ 22,611
		Total		**$ 7,704,378**	**$ 970,941**	**-$ 297,510**	**$ 8,377,809**	**$ 3,232,145**	**$ 349,497**	**-$ 115,683**	**$ 3,465,959**	**$ 4,904,372**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 13,334
Tools/Sentinel Lights	$ 11,556
Net Depreciation	$ 324,607

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

Year 2013 - Test

				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)		$ 81,285	$ 1,000		$ 82,285	$ 44,506	$ 15,607		$ 60,113	$ 22,172
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		$ 3,576,896	$ 49,073		$ 3,625,969	$ 1,240,813	$ 70,114		$ 1,310,927	$ 2,315,042
47	1835	Overhead Conductors & Devices		$ 1,105,837	$ 12,268		$ 1,118,105	$ 492,957	$ 18,508		$ 511,465	$ 606,640
47	1840	Underground Conduit		$ 178,392	$ 5,000		$ 183,392	$ 70,500	$ 2,850		$ 73,350	$ 110,042
47	1845	Underground Conductors & Devices		$ 913,950	$ 89,152		$ 1,003,102	$ 322,471	$ 21,847		$ 344,318	$ 658,784
47	1850	Line Transformers		$ 1,654,689	$ 59,767		$ 1,714,456	$ 617,781	$ 37,104		$ 654,885	$ 1,059,571
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 163,510			$ 163,510	$ 25,374	$ 12,035		$ 37,409	$ 126,101
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)		$ 22,237			$ 22,237	$ 8,745	$ 1,851		$ 10,596	$ 11,641
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	$ 41,287	$ 9,830		$ 51,117	$ 19,768
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 436,662			$ 436,662	$ 322,101	$ 19,693		$ 341,794	$ 94,868
10	1930	Transportation Equipment(5 years)		$ 90,317			$ 90,317	$ 78,365	$ 6,237		$ 84,602	$ 5,715
8	1940	Tools, Shop & Garage Equipment		$ 90,141	$ 5,000		$ 95,141	$ 58,960	$ 5,519		$ 64,479	$ 30,662
8	1945	Measurement & Testing Equipment		$ 12,694	$ 7,000		$ 19,694	$ 10,561	$ 1,643		$ 12,204	$ 7,490
8	1950	Power Operated Equipment		$ 136,522	$ 86,000		$ 222,522	$ 116,965	$ 14,662		$ 131,627	$ 90,895
8	1955	Communications Equipment		$ 37,334			$ 37,334	$ 31,888	$ 1,504		$ 33,392	$ 3,942
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		$ 29,688	$ 2,000		$ 31,688	$ 22,210	$ 1,491		$ 23,701	$ 7,987
47	1995	Contributions & Grants		-$ 983,191	-$ 92,000		-$ 1,075,191	-$ 231,884	-$ 31,517		-$ 263,401	-$ 811,790
WIP		Work In Progress		$ 22,611			$ 22,611	$ -			$ -	$ 22,611
		Total		**$ 8,377,809**	**$ 227,940**	**$ -**	**$ 8,605,749**	**$ 3,465,959**	**$ 255,875**	**$ -**	**$ 3,721,834**	**$ 4,875,928**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 34,355
Tools/Sentinel Lights	$ 10,157
Net Depreciation	$ 211,363

Table 2.9: Gross Assets 2008 to 2012(CGAAP), 2012 to 2013 (MCGAAP)

CCA Class	Description	2008 Board Approved	2008 Actual	Variance - 2008 Approved to 2008 Actual	2009 Actual	Variance - 2008 Actual to 2009 Actual	2010 Actual	Variance - 2009 Actual to 2010 Actual	2011 Actual	Variance - 2010 Actual to 2011 Actual	2012 Bridge (CGAAP)	Variance - 2011 Actual to 2012 Bridge (CGAAP)	2012 Bridge (MCGAAP)	Variance - 2011 Actual to 2012 Bridge (MCGAAP)	2013 Test (MCGAAP)	Variance - 2012 Bridge (MCGAAP) to 2013 Test
	Land & Buildings (Distribution Plant)															
47	1808 Buildings and Fixtures	91,864	91,864	0	91,864	0	91,864	0	91,864	0	91,864	0	91,864	0	91,864	0
	SUBTOTAL LAND & BUILDINGS	91,864	91,864	0	91,864	0	91,864	0	91,864	0	91,864	0	91,864	0	91,864	0
	Poles & Wires															
47	1830 Poles, Towers and Fixtures	3,093,852	2,936,921	-156,931	3,109,635	172,714	3,308,410	198,775	3,473,474	165,064	3,607,308	133,834	3,576,896	103,422	3,625,969	49,073
47	1835 Overhead Conductors and Devices	1,079,172	1,079,172	0	1,079,172	0	1,079,982	810	1,079,982	0	1,105,837	25,855	1,105,837	25,855	1,118,105	12,268
47	1840 Underground Conduit	154,957	163,101	8,144	165,709	2,608	167,448	1,739	173,392	5,944	179,592	6,200	178,392	5,000	183,392	5,000
47	1845 Underground Conductors and Devices	694,614	770,586	75,972	805,900	35,314	833,738	27,838	887,702	53,964	923,525	35,823	913,950	26,248	1,003,102	89,152
	SUBTOTAL POLES & WIRES	5,022,595	4,949,780	-72,815	5,160,416	210,636	5,389,578	229,162	5,614,550	224,972	5,816,262	201,712	5,775,075	160,525	5,930,568	155,493
	Line Transformers															
47	1850 Line Transformers	1,296,876	1,470,153	173,277	1,476,743	6,590	1,545,612	68,869	1,607,741	62,129	1,654,689	46,948	1,654,689	46,948	1,714,456	59,767
	SUBTOTAL LINE TRANSFORMERS	1,296,876	1,470,153	173,277	1,476,743	6,590	1,545,612	68,869	1,607,741	62,129	1,654,689	46,948	1,654,689	46,948	1,714,456	59,767
	Meters															
47	1860 Meters	266,122	320,348	54,226	390,397	70,049	447,604	57,207	454,082	6,478	810,996	356,914	810,996	356,914	812,676	1,680
47	1860 Smart Meters			0		0		0		0		0		0		0
	SUBTOTAL METERS	266,122	320,348	54,226	390,397	70,049	447,604	57,207	454,082	6,478	810,996	356,914	810,996	356,914	812,676	1,680
	IT Assets															
10	1920 Computer Equipement- Hardware	20,944	13,750	-7,194	39,560	25,810	39,324	-236	41,661	2,337	68,885	27,224	68,885	27,224	70,885	2,000
12	1925 Computer Equipment - Software	2,000	4,250	2,250	4,250	0	6,545	2,295	29,045	22,500	81,285	52,240	81,285	52,240	82,285	1,000
	SUBTOTAL IT ASSETS	22,944	18,000	-4,944	43,810	25,810	45,869	2,059	70,706	24,837	150,170	79,464	150,170	79,464	153,170	3,000
	Equipment															
8	1915 Office Furniture and Equipment	8,707	8,719	12	13,378	4,659	13,734	356	17,532	3,798	22,237	4,705	22,237	4,705	22,237	0
10	1930 Transportation Equipment	445,286	406,680	-38,606	437,863	31,183	437,863	0	437,863	0	526,979	89,116	526,979	89,116	526,979	0
8	1940 Tools, Shop and Garage Equipment	58,493	58,661	168	63,645	4,984	64,775	1,130	67,211	2,436	90,141	22,930	90,141	22,930	95,141	5,000
8	1945 Measurement and Testing Equipment	18,188	13,061	-5,127	12,694	-367	12,694	0	12,694	0	12,694	0	12,694	0	19,694	7,000
8	1950 Power Operated Equipment	108,187	108,187	0	112,402	4,215	135,802	23,400	135,802	0	136,522	720	136,522	720	222,522	86,000
8	1955 Communication Equipment	37,492	35,179	-2,313	37,334	2,155	37,334	0	37,334	0	37,334	0	37,334	0	37,334	0
	SUBTOTAL EQUIPMENT	676,353	630,487	-45,866	677,316	46,829	702,202	24,886	708,436	6,234	825,907	117,471	825,907	117,471	923,907	98,000
	Other Distribution Assets															
47	1995 Contributions and Grants	-384,206	-608,208	-224,002	-704,417	-96,209	-817,216	-112,799	-891,191	-73,975	-983,191	-92,000	-983,191	-92,000	-1,075,191	-92,000
	2055 Work in Progress		3,512	3,512	291	-3,221	28,592	28,301	20,502	-8,090	22,611	2,109	22,611	2,109	22,611	0
	SUBTOTAL OTHER DISTRIBUTION ASSETS	-384,206	-604,696	-220,490	-704,126	-99,430	-788,624	-84,498	-870,689	-82,065	-960,580	-89,891	-960,580	-89,891	-1,052,580	-92,000
	TOTAL GROSS FIXED ASSETS	**6,992,548**	**6,875,936**	**-116,612**	**7,136,420**	**260,484**	**7,434,105**	**297,685**	**7,676,690**	**242,585**	**8,389,308**	**712,618**	**8,348,121**	**671,431**	**8,574,061**	**225,940**

Variance Analysis on Gross Assets:

The Gross Asset Variance analysis for the variances highlighted in Table 2.9 of Exhibit 2, Tab 2, Schedule 2 is provided as follows for variances exceeding the materiality threshold of $50,000.

<u>2008 Board Approved vs. 2008 Actual</u>

The variance from the 2008 Board Approved Fixed Asset value compared to the actual 2008 Fixed Asset value was $(116,612).

The $(156,931) in account 1830 is primarily a result of postponing the Mill Line Upgrade indefinitely due to the closure of the Pulp mill in 2008. The balance of the variance can primarily be explained due to a decrease in actual 2007 capital expenditures to budgeted bridge year projections.

The variance of $75,972 in account 1845 is due to higher than budgeted capital expenditures in 2007 and 2008. The actual expenditures in 2007 were $49,941 compared to $14,000 budgeted and $54,000 in 2008 compared to $14,000 budgeted in the 2008 Cost of Service Application.

The variance of $173,277 in account 1850 is explained by an increased number in new service connections in the rural area. Due to the low density of the area, a single transformer often services one customer. The variance is also due to under budgeting for transformers in the 2007 bridge and 2008 test year for the 2008 Cost of Service application.

The variance of $54,226 in account 1860 is primarily due to SLHI not removing its stranded meters from the rate base in 2008. The amount budgeted in 2008 was $66,780.

Capital Contributions increased by $224,002 mainly due to the 2008 Cost of Service application omitting any new additions for Contributed Capital from 2006 to 2008.

<u>2008 Actual vs. 2009 Actual</u>

The variance from the 2008 Actual Fixed Asset value compared to the actual 2009 Fixed Asset value was $260,484.

The variance of $172,214 in account 1830 is due to capital expenditures made in 2009. This includes capital for SLHI's Pole replacement program as well as new connections. This variance is further explained in Exhibit 2, Tab 3, Schedule 2, Capital Projects by Year and USoA.

The variance of $70,049 in account 1860 is due to the installation of a new primary metering unit for a General Service 50 to 4,999 customer for a cost of $35,000. The amount also includes expenditures for smart meters installed in the General Service 50 to 4,999 customer rate class which were considered to be beyond the minimum functionality as per the Board's Smart Meter Guidelines, and therefore not included in Variance account 1555. These additions were offset by the removal of the GS > 50 kW conventional meters from the asset.

The variance of $(96,209) in account 1995 is due to contributions made for construction of new services required in accordance with SLHI's Conditions of Service and the DSC.

2009 Actual vs. 2010 Actual

The variance from the 2009 Actual Fixed Asset value compared to the actual 2010 Fixed Asset value was $297,685.

The variance of $198,775 in account 1830 is due to capital expenditures in 2010. This includes expenditures for SLHI's pole replacement program as well as costs for the Hwy 72 South upgrade, which is further explained in Exhibit 2, Tab 3, Schedule 2, Capital Projects by Year and USoA.

The variance of $68,869 in account 1850 is due to capital expenditures in 2010. This includes expenditures for costs related to the Hwy 72 South upgrade.

The variance of $57,207 in account 1860 is due to the installation of a primary central metering unit.

The variance of $(112,799) in account 1995 is due to contributions made for construction of new services required in accordance with SLHI's Conditions of Service and the DSC.

2010 Actual vs. 2011 Actual

The variance from the 2010 Actual Fixed Asset value compared to the actual 2011 Fixed Asset value was $242,585.

The variance of $165,064 in account 1830 is due to capital spending during the year. This includes costs for SLHI's pole replacement program and new connections and upgrades. This variance is further explained in Exhibit 2, Tab 3, Schedule 2, Capital Projects by Year and USoA.

The variance of $53,964 in account 1845 is due to capital spending during the year. In 2011SLHI constructed a new underground subdivision further explained in Exhibit 2, Tab 3, Schedule 2.

The variance of $62,129 in account 1850 is due to capital spending during the year. This includes transformers purchased for new connections as well as a transformer replacement.

The variance of $(73,975) in account 1995 is due to contributions made for construction of new services required in accordance with SLHI's Conditions of Service and the DSC.

2011 Actual vs .2012 Bridge Year (CGAAP)

The variance from the 2011 Actual Fixed Asset value compared to the actual 2012 Bridge Year Fixed Asset value under CGAAP is $712,618.

The variance of $133,834 in account 1830 is due to capital spending expected during the year under CGAAP. This includes costs for SLHI's pole replacement program and new connections and upgrades.

The variance of $356,914 in account 1860 and $52,240 in account 1925 is mainly due to the approval of SLHI's Smart Meter Disposal Application. The Smart Meter capital was transferred from Account 1555 to the asset accounts in September 2012.

The variance of $89,116 in account 1930 is due to expected capital spending during the year. This variance is further explained in Exhibit 2, Tab 3, Schedule 2, Capital Projects by Year and USoA.

The variance of $(92,000) in account 1995 is due to contributions expected for construction of new services required in accordance with SLHI's Conditions of Service and the DSC.

2011 Actual vs .2012 Bridge Year (MCGAAP)

The variance from the 2011 Actual Fixed Asset value compared to the actual 2012 Bridge Year Fixed Asset value under MCGAAP is $671,431.

The variances for accounts 1830, 1860, 1925, 1930 and 1995 are explained in the above section.

2012 Bridge Year (MCGAAP) vs. 2013 Test Year (MCGAAP)

The variances in gross assets for the 2012 Bridge Year compared to the 2013 Test Year are the result of capital expenditures in 2013, explained in detail in Exhibit 2, Tab 3, Schedule 2, Capital Projects by Year and USoA.

Accumulated Amortization Table:

Table 2.10 - Accumulated Amortization

CCA Class	Description	2008 Board Approved	2008 Actual	Variance - 2008 Approved to 2008 Actual	2009 Actual	Variance - 2008 Actual to 2009 Actual	2010 Actual	Variance - 2009 Actual to 2010 Actual	2011 Actual	Variance - 2010 Actual to 2011 Actual	2012 Bridge (CGAAP)	Variance - 2011 Actual to 2012 Bridge (CGAAP)	2012 Bridge (MCGAAP)	Variance - 2011 Actual to 2012 Bridge (MCGAAP)	2013 Test (MCGAAP)	Variance - 2012 Bridge (MCGAAP) to 2013 Test
	Land & Buildings (Distribution Plant)															
47	1808 Buildings and Fixtures	29,998	29,999	1	33,674	3,675	37,349	3,675	41,024	3,675	44,699	3,675	44,699	3,675	48,374	3,675
	SUBTOTAL LAND & BUILDINGS	29,998	29,999	1	33,674	3,675	37,349	3,675	41,024	3,675	44,699	3,675	44,699	3,675	48,374	3,675
	Poles & Wires															
47	1830 Poles, Towers and Fixtures	791,265	790,612	-653	914,997	124,385	1,047,333	132,336	1,186,272	138,939	1,314,009	127,737	1,240,813	54,541	1,310,927	70,114
47	1835 Overhead Conductors and Devices	345,324	345,324	0	388,491	43,167	431,690	43,199	474,889	43,199	518,589	43,700	492,957	18,068	511,465	18,508
47	1840 Underground Conduit	47,418	47,846	428	54,474	6,628	61,172	6,698	68,108	6,936	74,810	6,702	70,500	2,392	73,350	2,850
47	1845 Underground Conductors and Devices	199,360	204,396	5,036	236,632	32,236	269,982	33,350	305,490	35,508	338,292	32,802	322,471	16,981	344,318	21,847
	SUBTOTAL POLES & WIRES	1,383,367	1,388,178	4,811	1,594,594	206,416	1,810,177	215,583	2,034,759	224,582	2,245,700	210,941	2,126,741	91,982	2,240,060	113,319
	Line Transformers															
47	1850 Line Transformers	393,555	402,232	8,677	461,302	59,070	523,126	61,824	587,436	64,310	647,259	59,823	617,781	30,345	654,885	37,104
	SUBTOTAL LINE TRANSFORMERS	393,555	402,232	8,677	461,302	59,070	523,126	61,824	587,436	64,310	647,259	59,823	617,781	30,345	654,885	37,104
	Meters															
47	1860 Meters	13,666	87,074	73,408	94,938	7,864	114,630	19,692	126,510	11,880	173,035	46,525	173,035	46,525	228,292	55,257
47	1860 Smart Meters			0		0		0		0		0		0		0
	SUBTOTAL METERS	13,666	87,074	73,408	94,938	7,864	114,630	19,692	126,510	11,880	173,035	46,525	173,035	46,525	228,292	55,257
	IT Assets															
10	1920 Computer Equipement- Hardware	20,944	12,051	-8,893	18,067	6,016	23,251	5,184	28,983	5,732	41,287	12,304	41,287	12,304	51,117	9,830
12	1925 Computer Equipment - Software	600	1,268	668	2,118	850	3,121	1,003	4,805	1,684	44,506	39,701	44,506	39,701	60,113	15,607
	SUBTOTAL IT ASSETS	21,544	13,319	-8,225	20,185	6,866	26,372	6,187	33,788	7,416	85,793	52,005	85,793	52,005	111,230	25,437
	Equipment															
8	1915 Office Furniture and Equipment	5,155	4,613	-542	5,906	1,293	7,172	1,266	8,429	1,257	8,745	316	8,745	316	10,596	1,851
10	1930 Transportation Equipment	292,839	275,575	-17,264	323,705	48,130	369,954	46,249	384,744	14,790	400,463	15,719	400,463	15,719	426,393	25,930
8	1940 Tools, Shop and Garage Equipment	34,588	35,004	416	41,368	6,364	47,668	6,300	51,258	3,590	58,960	7,702	58,960	7,702	64,479	5,519
8	1945 Measurement and Testing Equipment	6,293	5,781	-512	7,009	1,228	8,276	1,267	9,474	1,198	10,561	1,087	10,561	1,087	12,204	1,643
8	1950 Power Operated Equipment	108,187	99,827	-8,360	105,068	5,241	109,335	4,267	113,113	3,778	116,965	3,852	116,965	3,852	131,627	14,662
8	1955 Communication Equipment	21,386	21,366	-20	25,260	3,894	28,779	3,519	30,354	1,575	31,888	1,534	31,888	1,534	33,392	1,504
	SUBTOTAL EQUIPMENT	468,448	442,166	-26,282	508,316	66,150	571,184	62,868	597,372	26,188	627,582	30,210	627,582	30,210	678,691	51,109
	Other Distribution Assets															
47	1995 Contributions and Grants	-95,399	-113,579	-18,180	-141,756	-28,177	-174,444	-32,688	-209,723	-35,279	-240,247	-30,524	-231,884	-22,161	-263,401	-31,517
	2055 Work in Progress			0		0		0		0		0		0		0
	SUBTOTAL OTHER DISTRIBUTION ASSETS	-95,399	-113,579	-18,180	-141,756	-28,177	-174,444	-32,688	-209,723	-35,279	-240,247	-30,524	-231,884	-22,161	-263,401	-31,517
	TOTAL ACCUMULATED AMORTIZATION	**2,215,179**	**2,249,389**	**34,210**	**2,571,253**	**321,864**	**2,908,394**	**337,141**	**3,211,166**	**302,772**	**3,583,821**	**372,655**	**3,443,747**	**232,581**	**3,698,131**	**254,384**

Variance Analysis on Accumulated Amortization:

Changes in accumulated amortization are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identified assets.

Table 2.10 shows the changes in accumulated amortization from 2008 Actual to the 2013 Test Year. The change in accumulated amortization is a result of capital expenditures, amortization expense each year, and write-offs of fully-amortized assets as appropriate over the five year period. From 2012 to 2013, the accumulated amortization relating to Smart Meter assets transferred to rate base as of September 1, 2012 (representing $104,611 of the variance from 2011 for account 1860 Smart Meters and $23,862 for account 1925 Computer Software) is considered in addition to the current year's amortization expense. This was offset by the removal of the stranded meter asset accumulated amortization in the amount of $112,869. In addition, SLHI retroactively adopted the half-year rule for capital asset additions back to 2008 (as per OEB policy, LDCs must use the half-year rule for amortization in the year of acquisition). This was reflected in a year-end adjusting entry that recorded a credit of ($24,352) in amortization expense (and a debit to amortization expense of $6,964 relating to contributed capital amounts) in 2012. Please refer to Exhibit 4, Tab 2, Schedule 7 for details of annual amortization expense for each asset account.

CAPITAL BUDGET

SLHI's Asset Management Plan identifies the capital projects required over a 5 year period based on the best available information for each year. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, SLHI may be required to adjust the capital project forecast as the knowledge of its system needs increases. As provided in Exhibit 2, Tab 3, Schedule 2, a portion of SLHI's capital investments are customer or municipal driven. All proposed capital projects for the 2012 Bridge Year and 2013 Test Year will be completed and in service in that year. Details of SLHI's capital budget for these periods are provided in Tables 2.12 to 2.18.

Provincial Sales Tax Impact

As a result of the implementation of HST in the province of Ontario on July 1, 2011, SLHI has considered the reduction in capital expenditures relating to the purchase of products and services due to the increased input tax credit (ITC). Neither the 2012 Bridge Year forecast nor the 2013 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2011.

Introduction:

SLHI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending for the 2012 Bridge Year and the 2013 Test year is broken down by account and by project in Exhibit 2, Tab 3, Schedule 2. Below is an analysis of SLHI's capital spending from 2007 to 2013.

Table 2.11 - Capital Spending Summary 2007 to 2013

Year	Total Distribution Plant ($)	Captial Contributions	Net Distribution Plant	General Plant	Total Capital net of Contributions	$ Increase/ (Decrease)	% Increase/ (Decrease)
2007	294,947	-50,141	244,806	17,064	261,870		
2008	358,225	-83,680	274,545	85,411	359,956	98,086	37.5%
2009	311,941	-96,209	215,732	74,816	290,548	-69,408	-19.3%
2010	381,539	-112,799	268,740	28,926	297,666	7,118	2.4%
2011	285,489	-73,975	211,514	32,240	243,754	-53,912	-18.1%
2012	217,475	-92,000	125,475	117,217	242,692	-1,062	-0.4%
2013	216,940	-92,000	124,940	103,000	227,940	-14,752	-6.1%

The updated filing requirements for Exhibit 2 (Rate Base) request actual historical summary information for the last 5 years.

In 2008, the main driver of the increase of 37.5% an increase in demand for new rural services which often required a transformer to service one customer due to low density as well as the inclusion of smart meters relating to services beyond minimum functionality (i.e. General Service > 50 kw customers) in account 1860.

For 2012 and 2013 SLHI's capital expenditures show a slight reduction due to the adoption of SLHI's new capitalization policy where non-major equipment and overheads not directly attributable to the asset are not capitalized. Tab 3, Schedule 2 provides details of all projects for both years.

The capital spending numbers reported above in Table 2.11 are excluding all amounts of smart meter spending. These expenditures were included in Account 1555 and transferred to the asset accounts as of September 1, 2012 as explained above in Tab 2, Schedule 3.

Capital Projects by Year and USoA

The tables below summarize SLHI's actual investment in construction projects for the years 2007 to 2011 plus projects for the 2012 Bridge Year (CGAAP) and 2012 Bridge Year (MCGAAP) and 2013 Test Year. Project descriptions are also provided. Individual projects above the materiality threshold of $50,000 have been listed individually.

Table 2.12 - 2007 Capital Projects

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)
Customer Demand	1	110,809	13,997			52,496	42,302	2,014
Renewal	2	125,969	125,969					
Reliabilty	3	4,877	4,877					
Subtotal		**241,655**	**144,843**	**0**	**0**	**52,496**	**42,302**	**2,014**
Contributed Capital (1995)		-50,141	-10,463		-16	-14,999	-14,399	-10,264
Subtotal		**191,514**	**134,380**	**0**	**-16**	**37,497**	**27,903**	**-8,250**
Projects < $50,000		**53,293**	35,460				17,833	
Total Distribution Plant		**244,807**						

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)
		0								
Subtotal		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Projects < $50,000		**17,064**								
Total General Plant		**17,064**								
Total Capital 2007		**261,871**								

2007 Distribution Plant Projects

Customer Demand

2007 Project #1 – New Connections

Cost: Total cost of $110,809.

Purpose: To connect new services.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: SLHI connected 29 new services and installed 11 new transformers.

<u>Renewal</u>

<u>2007 Project #2 – Pole Replacement Program</u>

Cost: Total cost of $125,969.

Purpose: To replace poles at end of life or due to deterioration.

Need: Deteriorated poles at the end of their useful life in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through SLHI's inspection and maintenance program.

Scope: In 2007 approximately 35 poles were replaced.

<u>Reliability</u>

<u>2007 Project #3 – Hwy 72 South Upgrade</u>

Cost: Total Cost of $118,123 (2007: $4,877, 2008: $18,372, 2009: $1,845, 2010: $81,737, 2011: $3,033, 2012: $8,259)

Purpose: To convert voltage from 7200 to 14.4 kV.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI will upgrade system voltage from 7200 to 14.4 kV for a span of approximately 12 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth.

Scope: The project will be completed over a span of approximately 4 years. The project began in 2007, but the majority of work was completed in 2010 based on other projects planned throughout the years as well as projects initiated by customer demand. The project involved replacing approximately 12 transformers and related equipment (cutouts and arrestors) for a 12 kilometer span as well as coordinating work to be completed with Bell Telephone for work done on Bell Telephone owned poles.

<u>2007 Capital Contributions</u>

Source of Funds: $ 50,141 (Account 1995)

Need: SLHI must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions from Developers and others is a significant source of funds for SLHI. Capital contributions are charged in compliance with the Conditions of Service using the Economic Evaluation Calculation as required by the DSC.

Table 2.13 - 2008 Capital Projects

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	18,372	18,372					
Customer Demand	5	198,344	11,707		5,448	45,468	133,674	2,047
Renewal	6	104,030	104,030					
Subtotal		**320,746**	**115,737**	**0**	**5,448**	**45,468**	**133,674**	**2,047**
Contributed Capital (1995)		-83,680	-7,896		-135	-39,838	-35,310	-500
Subtotal		**237,066**	**107,841**	**0**	**5,313**	**5,630**	**98,364**	**1,547**
Projects < $50,000		**37,479**	25,252		2,141	8,563	1,523	
Total Distribution Plant		**274,545**						

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)**
Transportation Equipment	7	68,430				68,430					
Subtotal		**68,430**	**0**	**0**	**0**	**68,430**	**0**	**0**	**0**	**0**	
Projects < $50,000		**16,981**	1,652	1,753	2,160		6,177	873	1,690	1,268	1,408
Total General Plant		**85,411**									
Total Capital 2008		**359,956**									

2008 Distribution Plant Projects

Reliability

2008 Project #3 – Hwy 72 South Upgrade

Cost: Total Cost $118,123 (2007: $4,877, 2008: $18,372, 2009: $1,845, 2010: $81,737, 2011: $3,033, 2012: $8,259)

Purpose: To convert voltage from 7200 to 14.4 kV.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI will upgrade system voltage from 7200 to 14.4 kV for a span of approximately 12 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth.

Scope: The project will be completed over a span of approximately 4 years. The project began in 2007, but the majority of work was completed in 2010 based on other projects planned throughout the years as well as projects initiated by customer demand. The project involved replacing approximately 12 transformers and related equipment (cutouts and arrestors) for a 12 kilometer span as well as coordinating work to be completed with Bell Telephone for work done on Bell Telephone owned poles.

<u>Customer Demand</u>

<u>2008 Project #5 – New Connections</u>

Cost: Total cost of $198,344 (Account 1830, 1840, 1845, 1850, 1860)

Purpose: To connect new services.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: In 2008 SLHI connected 29 new services and installed 22 new transformers.

<u>Renewal</u>

<u>2008 Project #6 – Pole Replacement Program</u>

Cost: $104,030 (Account 1830)

Purpose: To replace poles at end of life or due to deterioration.

Need: Deteriorated poles at the end of their useful life in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through SLHI's inspection and maintenance program.

Scope: In 2008 approximately 30 poles were replaced.

2008 Capital Contributions

Source of Funds: $ 83,680 (Account 1995)

Need: SLHI must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions from Developers and others is a significant source of funds for SLHI. Capital contributions are charged in compliance with the Conditions of Service using the Economic Evaluation Calculation as required by the DSC.

General Plant

2008 Project #7 - 2008 Ford F/S Duty

Cost: $68,430

Purpose: A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, increased reliability, increased fuel economy, reduced emissions and new vehicle warranty which decreases maintenance expenses.

Need: SLHI requires a reliable and cost effective fleet of work platforms, pickup trucks and trailers in order to respond to emergencies and perform field work as required.

Scope: Purchase new 2008 Ford F/S Duty 1 ton truck to replace depreciated 1998 1 ton truck.

Table 2.14 - 2009 Capital Projects

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	1,845	1,845					
Customer Demand	12	50,644	15,260		782	28,012	6,590	
Renewal	13	134,275	134,275					
Customer Connections and Metering	14	58,865						58,865
Subtotal		**245,629**	**151,380**	**0**	**782**	**28,012**	**6,590**	**58,865**
Contributed Capital (1995)		-96,209	-18,603		0	-18,969	-31,857	-26,780
Subtotal		**149,420**	**132,777**	**0**	**782**	**9,043**	**-25,267**	**32,085**
Projects < $50,000		**66,311**	20,112		1,826	7,302		37,071
Total Distribution Plant		**215,731**						

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)
		0									
		0									
Subtotal		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Projects < $50,000		**74,816**	4,659	25,810		31,183	4,984		4,215	2,155	1,810
Total General Plant		**74,816**									
Total Capital 2009		**290,547**									

2009 Distribution Plant Projects

Reliability

2009 Project #3 – Hwy 72 South

Cost: Total Cost $118,123 (2007: $4,877, 2008: $18,372, 2009: $1,845, 2010: $81,737, 2011: $3,033, 2012: $8,259)

Purpose: To convert voltage from 7200 to 14.4 kV.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI will upgrade system voltage from 7200 to

14.4 kV for a span of approximately 12 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth.

Scope: The project will be completed over a span of approximately 4 years. The project began in 2007, but the majority of work was completed in 2010 based on other projects planned throughout the years as well as projects initiated by customer demand. The project involved replacing approximately 12 transformers and related equipment (cutouts and arrestors) for a 12 kilometer span as well as coordinating work to be completed with Bell Telephone for work done on Bell Telephone owned poles.

Customer Demand

2009 Project #12 – New Connections

Cost: $50,644 (Account 1830, 1840, 1845, 1850)

Purpose: To connect new services.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: In 2009 SLHI connected 27 new services and installed 11 new transformers.

Customer Connections and Metering

2009 Project #14 – Smart Meters GS > 50 kW

Cost: $58,865 (Account 1860)

Purpose: Replace all meters with a smart meter.

Need: SLHI contracted out the installation of smart meters in 2009 to be performed by Olameter. At the time SLHI made the decision to install smart meters for GS > 50 kW customers even though this was considered to be beyond minimum functionality. SLHI considered the future benefits of completing the replacements in its decision. Among the benefits would be the eventual phase out of manual meter reads as well as increased data available for diagnostics and trouble shooting.

Scope: Completed the installation of Approximately 50 meters for GS > 50 kW customers.

Renewal

2009 Project #13 – Pole Replacement Program

Cost: $134,275 (Account 1830)

Purpose: To replace poles at end of life or due to deterioration.

Need: Deteriorated poles at the end of their useful life in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through SLHI's inspection and maintenance program.

Scope: In 2009 approximately 38 poles were replaced.

<u>2009 Capital Contributions</u>

Source of Funds: $ 96,209 (Account 1995)

Need: SLHI must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions are charged in compliance with SLHI's Conditions of Service using the Economic Evaluation Calculation as required by the DSC.

<u>General Plant</u>

In 2009 SLHI had no General Plant projects that were over the materiality threshold.

Table 2.15- 2010 Capital Projects

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)
Reliabiity	3	81,737	61,582				20,155	
Customer Demand	17	98,549	13,719			29,577	48,714	6,539
Renewal	18	122,818	122,008	810				
Customer Demand	20	50,668						50,668
Subtotal		**353,772**	**197,309**	**810**	**0**	**29,577**	**68,869**	**57,207**
Contributed Capital (1995)		-112,799	-4,682			-14,359	-41,901	-51,857
Subtotal		**240,973**	**192,627**	**810**	**0**	**15,218**	**26,968**	**5,350**
Projects < $50,000		**27,767**			1,739	15,949	10,079	
Total Distribution Plant		**268,740**						

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)
		0									
		0									
Subtotal		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Projects < $50,000		**28,926**	356	320	2,295		1,130		23,400		1,425
Total General Plant		**28,926**									
Total Capital 2010		**297,666**									

2010 Distribution Plant Projects

Reliability

2010 Project #3 – Hwy 72 South

Cost: Total Cost $118,123 (2007: $4,877, 2008: $18,372, 2009: $1,845, 2010: $81,737, 2011: $3,033, 2012: $8,259)

Purpose: To convert voltage from 7200 to 14.4 kV.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI will upgrade system voltage from 7200 to 14.4 kV for a span of approximately 12 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth.

Scope: The project will be completed over a span of approximately 4 years. The project began in 2007, but the majority of work was completed in 2010 based on other projects planned throughout the years as well as projects initiated by customer demand . The project involved replacing approximately 12 transformers and related equipment (cutouts and arrestors) for a 12 kilometer span as well as coordinating work to be completed with Bell Telephone for work done on Bell Telephone owned poles.

Customer Demand

2010 Project #17 – New Connections

Cost: Total cost of $98,549

Purpose: To connect new services.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: In 2010 SLHI connected 27 new services and installed 19 new transformers.

Renewal

2010 Project #18 – Pole Replacement Program

Cost: $122,818 (Accounts 1830)

Purpose: To replace poles at end of life or due to deterioration.

Need: Deteriorated poles at the end of their useful lives in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through SLHI's inspection and maintenance program. s.

Scope: For 2010 approximately 20 priority poles were replaced.

Customer Demand

2010 Project #20 – MNR Central Metering

Cost: Total costs of $53,797 (2010:$50,668, 2011: $3,109)

Purpose: Perform work requested by the customer

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: Installed 2 primary central metering units for the customer.

Capital Contributions

Source of Funds: $ 112,799 (Account 1995)

Need: SLHI must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions are charged in compliance with SLHI's Conditions of Service using the Economic Evaluation Calculation as required by the DSC.

General Plant

In 2010 SLHI had no General Plant projects that were over the materiality threshold.

Table 2.16- 2011 Capital Projects

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	3,033	3,033					
Reliability	23	19,668	18,689			979		
Customer Demand	24	82,534	12,906		5,944	23,355	36,960	3,369
Renewal	25	116,167	116,167					
Customer Connections and Metering	20	3,109						3,109
Subtotal		**224,511**	**150,795**	**0**	**5,944**	**24,334**	**36,960**	**6,478**
Contributed Capital (1995)		-73,975	-20,440			-40,596	-12,539	-400
Subtotal		**150,536**	**130,355**	**0**	**5,944**	**-16,262**	**24,421**	**6,078**
Projects < $50,000		**60,978**	32,967			12,921	15,090	
Total Distribution Plant		**211,514**						

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)
		0									
		0									
Subtotal		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Projects < $50,000		**32,240**	3,798	2,337	22,500		2,436				1,169
Total General Plant		**32,240**									
Total Capital 2011		**243,754**									

2011 Distribution Plant Projects

Customer Connections and Metering

2011 Project #20 – MNR Central Metering

Cost: Total costs of $53,797 (2010:$50,668, 2011: $3,109)

Purpose: To complete project carried over from 2010.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: Completed the installation of 2 primary central metering units for the customer.

Reliability

2011 Project #3 – Hwy 72 South

Cost: Total Cost $118,123 (2007: $4,877, 2008: $18,372, 2009: $1,845, 2010: $81,737, 2011: $3,033, 2012: $8,259)

Purpose: To convert voltage from 7200 to 14.4 kV.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI will upgrade system voltage from 7200 to 14.4 kV for a span of approximately 12 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth.

Scope: The project will be completed over a span of approximately 4 years. The project began in 2007, but the majority of work was completed in 2010 based on other projects planned throughout the years as well as projects initiated by customer demand . The project involved replacing approximately 12 transformers and related equipment (cutouts and arrestors) for a 12 kilometer span as well as coordinating work to be completed with Bell Telephone for work done on Bell Telephone owned poles.

2011 Project #23 – Moosehorn Road Voltage Upgrade

Cost: Total cost of $65,348(2011:$19,668, 2012: $45,680)

Purpose: To convert voltage from 7200 to 14.4 kV and replace poles.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI upgraded system voltage from 7200 to 14.4

kV for a span of approximately 3 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth. In addition to the voltage upgrade, pole replacements were completed in order to replace aging poles which were originally installed by Ontario Hydro and ranged from 35 to 4o feet tall. The standard pole height for the area is 45 feet. Therefore, the poles were replaced with 45 foot poles.

Scope: The project was completed over 2 years and involved replacing 22 poles with new 45 foot poles, transferring conductor to the new poles and replacing 4 transformers and related equipment.

Customer Demand

Project #24- New Connections

Cost: $82,534

Purpose: To connect new services.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: In 2011 SLHI connected 31 new services and installed 12 new transformers.

Renewal

2011 Project #25 – Pole Replacement Program

Cost: $116,167

Purpose: To replace poles at end of life or due to deterioration.

Need: Deteriorated poles at the end of their useful lives in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through SLHI's inspection and maintenance program.

Scope: For 2011 approximately 15 priority poles were replaced.

Capital Contributions

Source of Funds: $ 73,975 (Account 1995)

Need: SLHI must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions are charged in compliance with SLHI's Conditions of Service using the Economic Evaluation Calculation as required by the DSC.

General Plant

In 2011 SLHI had no General Plant projects that were over the materiality threshold.

Table 2.17- 2012 Budgeted 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	45,680	45,288		392			
Customer Demand	30	107,976	49,304		1,318	30,053	19,920	7,381
		0						
Subtotal		**161,915**	**102,851**	**0**	**1,710**	**30,053**	**19,920**	**7,381**
Contributed Capital (1995)		-92,000	-19,196		-30	-27,520	-26,420	-18,834
Subtotal		**69,915**	**83,655**	**0**	**1,680**	**2,533**	**-6,500**	**-11,453**
Projects < $50,000		**55,560**	28,532				27,028	
Total Distribution Plant		**125,475**						

						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	89,116				89,116					
Subtotal		**89,116**	**0**	**0**	**0**	**89,116**	**0**	**0**	**0**	**0**	**0**
Projects < $50,000		**28,101**	6,000	7,881	1,500		10,000		720		2,000
Total General Plant		**117,217**									
Total Capital 2012		**242,692**									

2012 Distribution Plant Projects

Customer Demand

2012 Project #30 – New Connections

Cost: $107,976

Purpose: To connect new services.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: In 2012 SLHI expects to connect 17 new services and install 6 new transformers.

Reliability

2012 Project #3- Hwy 72 South (Completion)

Cost: Total Cost $118,123 (2007: $4,877, 2008: $18,372, 2009: $1,845, 2010: $81,737, 2011: $3,033, 2012: $8,259)

Purpose: To convert voltage from 7200 to 14.4 kV.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI will upgrade system voltage from 7200 to 14.4 kV for a span of approximately 12 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth.

Scope: The project will be completed over a span of approximately 4 years. The project began in 2007, but the majority of work was completed in 2010 based on other projects planned throughout the years as well as projects initiated by customer demand . The project involved replacing approximately 12 transformers and related equipment (cutouts and arrestors) for a 12 kilometer span as well as coordinating work to be completed with Bell Telephone for work done on Bell Telephone owned poles.

2012 Project #23 – Moosehorn road Voltage Upgrade (Completion)

Cost: Total cost of $65,348(2011:$19,668, 2012: $45,680)

Purpose: To convert voltage from 7200 to 14.4 kV and replace poles.

Need: In order to improve reliability of the system as well as reduce line loss and provide one uniform voltage, SLHI upgraded system voltage from 7200 to 14.4

kV for a span of approximately 3 kilometers. This upgrade will also reduce inventory costs by eliminating the need to carry two different voltages of transformers as well as increase capacity for future growth. In addition to the voltage upgrade, pole replacements were completed in order to replace aging poles which were originally installed by Ontario Hydro and ranged from 35 to 4o feet tall. The standard pole height for the area is 45 feet. Therefore, the poles were replaced with 45 foot poles.

Scope: The project was completed over 2 years and involved replacing 22 poles with new 45 foot poles, transferring conductor to the new poles and replacing 4 transformers and related equipment.

<u>Capital Contributions</u>

*Source of Funds***:** $92,000 (Account 1995)

Need: SLHI must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions are charged in compliance with SLHI's Conditions of Service using the Economic Evaluation Calculation as required by the DSC.

<u>General Plant</u>

<u>2012 Project #35 – Line Truck Betterment</u>

Cost: $89,116 (Account 1930)

Purpose: To extend the life of 2002 Freightliner Truck

Need: SLHI requires a reliable and cost effective fleet of work platforms, pickup trucks and trailers in order to respond to emergencies and perform field work as required. SLHI evaluated two options before deciding to perform extensive repairs on the current 2002 Freightliner. One option was to replace the vehicle with a used newer model of the same truck at a cost of $150,000. The second option to repair the existing vehicle provided lower costs and is expected to extend the life for another five years. The repairs were needed as the undercarriage of the vehicle was rusting out, and was identified as a safety hazard. The reliability of the vehicle, which is needed to perform essential work for the utility, was significantly decreased due to the condition of the undercarriage of the vehicle.

Scope: The costs include the transportation of the vehicle to the repair centre, rental of a temporary replacement line truck, and total costs to complete the required repairs on the vehicle including welding the frame and undercarriage, replacing hoses and wiring.

Table 2.18- 2013 Test Year Budgeted Capital Projects

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)
Customer Demand	38	58,438	6,929			20,216	29,613	1,680
Reliability	40	72,200				72,200		
Subtotal		**130,638**	**6,929**	**0**	**0**	**92,416**	**29,613**	**1,680**
Contributed Capital (1995)		-92,000	-19,196		-30	-27,520	-26,420	-18,834
Subtotal		**38,638**	**-12,267**	**0**	**-30**	**64,896**	**3,193**	**-17,154**
Projects < $50,000		**86,302**	54,412			1,736	30,154	
Total Distribution Plant		**124,940**						

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)
Backhoe	41	86,000							86,000		
Subtotal		**86,000**	**0**	**0**	**0**	**0**	**0**	**0**	**86,000**	**0**	**0**
Projects < $50,000		**17,000**		2,000	1,000		5,000	7,000			2,000
Total General Plant		**103,000**									
Total Capital 2013		**227,940**									

<u>2013 Distribution Plant Projects</u>

<u>*Customer Demand*</u>

<u>2013 Project #38 – New Connections</u>

Cost: $58,438

Purpose: To connect new services.

Need: SLHI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for services in accordance with SLHI's Conditions of Service.

Scope: In 2013 SLHI expects to connect 10 new services and install 6 new transformers.

Reliability

2013 Project #40 – Sturgeon River Submarine Cable

Cost: $72,200

Purpose: To replace aging submarine cable feeding one private customer and support future load for growth across Sturgeon River.

Need: The submarine cable was installed in the early 1970s by the former Ontario Hydro (Hydro One). The cable is nearing its end of life and poses a threat to reliability due to deterioration. The outside concentric neutral has been repaired 3 or 4 times to date and fluctuating water levels causes the copper concentric to deteriorate. Currently the cable feeds one customer who is a seasonal tourist operator, but the area was recently identified as an opportunity for future residential growth, therefore replacing the cable will ensure that SLHI is able to meet future customer demand for power in that area.

Scope: Replace approximately 2000 meters of underground submarine cable

Capital Contributions

Source of Funds: $92,000 (Account 1995)

Need: SLHI must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions are charged in compliance with SLHI's Conditions of Service using the Economic Evaluation Calculation as required by the DSC.

General Plant

2013 Project #41 – Backhoe purchase

Cost: $86,000 (Account 1950)

Purpose: To reduce costs associated with tree trimming and line clearing.

Need: SLHI currently contracts out tree trimming/line clearing to an outside contractor if the work involves a significant area, or an area inaccessible by SLHI's current fleet. The current projection for 2013 and beyond is to clear approximately 50 spans of line per year. This is due to regular inspections performed through the maintenance program and the rapidly growing vegetation in most rural areas of SLHI's distribution system. The costs and benefits of continuing to contract out the work were compared to those of purchasing the new backhoe with attached brush hog. Purchasing the brush hog was found to be more cost effective as well as providing additional benefits related to other types of work including setting/straightening poles, trenching and other operations. The backhoe will also reduce the amount of physical labour required for tree trimming which will reduce the risk of injuries related to tree trimming and line clearing.

Scope: Purchase a backhoe with attached brush hog at a cost of $86,000.

Asset Management Plan Summary:

SLHI is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. SLHI's distribution assets range in age from new to over 60 years old.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of SLHI's physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates. SLHI did not have a formal asset management plan in place for the last Cost of Service Application in 2008. In 2009 SLHI purchased an Asset Management package from Automated Solutions International Inc. This included a computer (Toughbook) installed with the program RamSys, which was utilized in the field to collect information on SLHI's distribution assets. In 2011 SLHI purchased a mapping system to be developed by Automated Solutions. This system is integrated with the RamSys system in order to maximize efficiency and also help to develop and maintain SLHI's infrastructure. In early 2012, SLHI contracted Automated Solutions International Inc. to assist in the development of a comprehensive asset management plan, which incorporated the information collected through RamSys and the mapping information. Accompanying this Schedule as Appendix 2-A is a copy of our Asset Management Plan. It is important to note that SLHI's Asset Management Plan is a living document and as such will be reviewed each year and updated for future years as more information is collected. Also SLHI will review the current and potential future activities expected to form the major parts of the Asset Management Plan in the future.

SLHI has provided the forecast for 2013, 2014 and 2015 capital expenditures in Tables 2.30, 2.31 and 2.32 below. Amounts are reported under MCGAAP. The annual replacement costs are engineering estimates only and the actual expenditure levels in the capital budgets could be adjusted based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.).

Table 2.30 - 2013 Distribution System Capital Expenditure Forecast

Budget Year	Project No.	Category	Project	Total
2013	1	Renewal	Pole Replacement Program	$46,923
2013	2	Customer Demand	New Connections	$58,438
2013	3	Customer Connections and Metering	General Upgrades	$39,380
2013	4	Reliability	Sturgeon River Submarine Cable	$72,200
2013	5	Other	Backhoe	$86,000
2013	6	Other	Amcorder Recording Ammeter	$7,000
2013	8	Other	Tools - general	$5,000
2013	9	Other	Office Computers	$3,000
			Total:	$317,941

Table 2.31 - 2014 Distribution System Capital Expenditure Forecast

Budget Year	Project No.	Category	Project	Total
2014	1	Renewal	Pole Replacement Program	$48,502
2014	2	Customer Demand	New Connections	$79,235
2014	3	Customer Connections and Metering	General Upgrades	$48,224
2014	4	Reliability	South Shore Drive Conversion	$12,484
2014	5	Reliability	Primary U/G Cable Rear Hwy 72	$19,842
2014	6	Other	Locator replacement	$5,000
2014	7	Other	Hydraulic Cutters	$5,000
2014	8	Other	Power Operated Equipment	$15,000
2014	9	Other	Tools - General	$10,000
2014	10	Other	Computers and Software	$8,000
2014	11	Other	Snow Machine	$15,000
2014	12	Other	Green Energy Project	$50,000
			Total:	$316,287

Table 2.32 - 2015 Distribution System Capital Expenditure Forecast

Budget Year	Project No.	Category	Project	Total
2015	1	Renewal	Pole Replacement Program	$24,863
2015	2	Customer Demand	New Connections	$87,715
2015	3	Customer Connections and Metering	General Upgrades	$10,671
2015	4	Reliability	Rear Front Street Reconductoring	$44,297
2015	5	Reliability	F2 Blue Phase Reconductor	$51,823
2015	6	Other	Tools - General	$10,000
2015	7	Other	Vehicles - 3/4 ton	$35,000
2015	8	Other	Computers and Software	$1,500
2015	9	Renewal	Cross Arm Replacement	$21,631
2015	10	Other	Computers and Software	
2015	11	Other	Snow Machine	
2015	12	Other	Green Energy Project	
			Total:	$287,500

Capitalization Policy

Overview

SLHI has historically applied the following general capitalization policies and principles based on Canadian Generally Accepted Accounting Principles ("CGAAP"), as well as guidelines set out by the Ontario Energy Board, where applicable. Going forward capitalization will conform to the Modified International Financial Reporting Standards (MIFRS). The information found in this section applies to capitalization under CGAAP only. Changes due to modification of capitalization and depreciation policies to be more in line with MIFRS are described in Tab 5 – Summary of Changes as a Result of Modifying Capitalization and Depreciation Policy "Modified" CGAAP (MCGAAP).

The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit greater than one year will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset will be capitalized.
- With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.

Capitalization Guidelines

SLHI capitalizes directly attributable expenses related to the construction of distribution system assets comprising of material, direct labour, engineering and vehicle costs. In determining which expenses are eligible for capitalization, SLHI uses the following guidelines:

Directly attributable:

- Employee costs and benefits incurred by employees working directly on construction or acquisition of asset
- Major Equipment as defined in SLHI ‘s Equipment Approval Process
- Cost of site preparation
- Initial delivery and assembly
- Testing costs
- Professional fees

Not directly attributable

- Administrative and other general overhead costs
- Non-major equipment
- Feasibility studies
- Start-up or pre-opening costs
- Training costs
- Abnormal waste
- Costs incurred when construction is interrupted, unless certain criteria are met
- Cost of opening a new facility
- Relocation costs
- Costs incurred in using or redeploying an item

Other guidelines are as follows:

- Fixed assets have a useful life of more than one year and are subject to depreciation. Any directly attributable expenditures to acquire, construct or better that asset should therefore be capitalized. All other expenditures should be expensed as a period expense in the year they occur.
- Professional judgment must be used to determine when an expense is classified as capital or an operating expense. A betterment (capitalized) will enhance the service potential of an existing asset by increasing its service capacity, lowering the operational costs associated with the asset, extend the useful life of the asset, or

improving the output of that asset. If the expenditure does not meet these tests, it will likely be considered an expense. Period expenses generally do not result in an improvement to the existing asset. The expense would have been required to keep the asset operating in the same capacity as it was originally.

- In order to be capitalized, an item must meet the minimum threshold requirement of two hundred dollars ($200.00).

Major Spare Parts and Stand-by Equipment

Major Spare Parts and Stand-by Equipment will be accounted for as property, plant and equipment capital assets, as per Article 410 of the OEB APH as follows:

- Major Spare Parts and Stand-by Equipment will be accounted for as property, plant and equipment capital assets.

- Depreciation of the Major Spare Parts and Stand-by Equipment will begin when the equipment is capable of operating in the manner that is intended by management, which will usually be when the major spare parts are installed and brought into service.

10.4 Residual Value & Useful Life

Sioux Lookout Hydro Inc. will review at least annually the residual value and useful life of each asset. Reviews ensure that the carrying amount does not differ materially from what would be determined using fair value at the balance sheet date.

Increases and decreases in capital assets during reviews will be reported as a profit or loss in equity. If expectations differ from previous estimates the changes shall be accounted for as a change in estimate and be applied prospectively.

The following factors will be considered when determining the useful life of an asset:

a) Expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output.
b) Expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance program, and the care and maintenance of the asset while idle.
c) Technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset.
d) Legal or similar limits on the use of the asset, such as the expiry dates of related leases.

If the expected life of a specific asset differs significantly, the useful life can be modified.

Service Quality & Reliability Performance

SLHI's achieved levels of service quality for the year 2008 through 2011 are provided in Appendix 2-D. SLHI's performance has been above the established standard for these reported years.

ALLOWANCE FOR WORKING CAPITAL

Overview and Calculation by Account:

In calculating the Working Capital Allowance ("WCA") for 2012 and 2013, SLHI used the default 13% of the cost of power and controllable expenses. This is based on the Board's update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital, dated June 28, 2012. Table 2.40 below shows the changes in working capital allowance from 2008 to 2013.

Table 2.40: Sioux Lookout Hydro Inc.'s Cost of Power and Controllable Expense

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MCGAAP)	2013 Test (MCGAAP)
Distribution Expenses - Operations	421,827	426,324	396,303	493,191	479,052	543,453	584,640	628,363
Distribution Expenses - Maintenance	87,281	91,130	94,702	116,678	106,053	320,907	320,616	196,645
Billing and Collecting	349,826	365,700	381,340	310,460	265,561	248,619	298,102	316,965
Administrative & General Expenses	260,892	263,826	267,718	240,621	302,369	430,279	389,675	407,460
Taxes Other than Income Taxes	8,700					4,986	4,986	4,986
Total Eligible Distribution Expenses	1,128,526	1,146,980	1,140,063	1,160,950	1,153,035	1,548,244	1,598,019	1,554,419
Power Supply Expenses	8,438,014	5,560,391	3,497,912	5,202,375	6,153,109	7,558,782	7,558,782	7,802,913
Total Working Capital Expenses	9,566,540	6,707,371	4,637,975	6,363,325	7,306,144	9,107,026	9,156,801	9,357,332
Working Capital Allowance	1,434,981	1,006,106	695,696	954,499	1,095,922	1,183,913	1,190,384	1,216,453
Working Capital Allowance %	15%	15%	15%	15%	15%	13%	13%	13%

SLHI's working capital allowance is forecast to be $1,216,453 for 2013 based on the "13% Allowance Approach" outlined on page 17 of Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012, which is 13% of the sum of the Cost of Power and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Administration and General).

Cost of Power Forecast

SLHI's cost of power forecast for 2012 and 2013 were derived by applying the appropriate rates for the period in question to the forecasted energy sales and demand. More specifically, the following steps were followed:

Energy Purchases

The 2012 and 2013 forecasted sales in kWh and kW, produced by the load forecasting model and adjusted for the impact of CDM activities were used. To calculate the cost of commodity, the load forecast for each year was allocated between non-RPP and RPP kWh sales based on 2011 actuals. Both volumes for both years were uplifted by the proposed 2013 Total Loss Factor (TLF) of 1.0897 as calculated in Appendix 2-R of the Chapter 2 Appendices. Since the TLF for 2012 is unknown, SLHI believes it to be reasonable to apply the 5 year average to 2012 as calculated in Appendix 2-R.

The loss adjusted RPP forecast for both 2012 and 2013 are multiplied by the most current RPP Price issued by the Board which is found in the *Regulated Price Plan Report May 1, 2012 to April 30, 2013* dated April 2, 2012. The rate used is the average supply cost for a RPP consumer which is currently $0.08069/kWh. The loss adjusted non-RPP forecast for both 2012 and 2013 are multiplied by the sum of the Total Adjustment as listed in the Board's Price Report ($.05772/kWh) and the applicable "term average" HOEP forecast provided by Navigant dated April 9, 2012 (2012=$0.02105/kWh; 2013=$0.02362/kWh).

Network and connection costs are determined by using the loss adjusted load forecast and applying the approved rates from the Board's decision in EB-2011-0197 to the 2012 applicable volumes and the proposed 2013 rates as calculated in the Retail Transmission Service Rates excel file. The Wholesale Market Service cost and Rural Rate Assistance costs are determined by using the loss adjusted load forecasts for 2012 and 2013 at $0.0052/kWh and $0.0011/kWh respectively.

As discussed above, SLHI has used the most current rates to calculate the cost of power, understanding that these rates may require updating as new rates become effective during the Cost of Service Application process. Table 2.41 shown below is the calculated 2012 and 2013 Cost of Power (MCGAAP):

Table 2.41 - Cost of Power

2012 Load Forecast	kWh	kW	2011 % RPP		
Residential	33,651,737		95%		
General Service < 50 kW	12,513,525		99%		
General Service 50 to 4,999 kW	26,167,747	66081	9%		
Street Lighting	499,208	1505	2%		
Unmetered Scattered Load	13,662		100%		
Total	**72,845,879**	**67,586**			

Electricity - Commodity RPP	2012	2012 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2012**	
Residential	31,969,150	1.0897	34,836,783	0.08069	$2,810,980
General Service < 50 kW	12,388,390	1.0897	13,499,628	0.08069	$1,089,285
General Service 50 to 4,999 kW	2,355,097	1.0897	2,566,349	0.08069	$207,079
Street Lighting	9,984	1.0897	10,880	0.08069	$878
Unmetered Scattered Load	13,662	1.0897	14,887	0.08069	$1,201
Total	**46,736,283**		**50,928,528**		**$4,109,423**

Electricity - Commodity Non-RPP	2012	2012 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2012**	
Residential	1,682,587	1.0897	1,833,515	0.07877	$144,426
General Service < 50 kW	125,135	1.0897	136,360	0.07877	$10,741
General Service 50 to 4,999 kW	23,812,650	1.0897	25,948,645	0.07877	$2,043,975
Street Lighting	489,224	1.0897	533,108	0.07877	$41,993
Unmetered Scattered Load	0	1.0897	0	0.07877	$0
Total	**26,109,596**		**28,451,627**		**$2,241,135**

Transmission - Network		Volume			
Class per Load Forecast RPP		**Metric**		**2012**	
Residential		kWh	36,670,298	0.0055	$201,687
General Service < 50 kW		kWh	13,635,988	0.005	$68,180
General Service 50 to 4,999 kW		kW	66081	2.0041	$132,433
Street Lighting		kW	1505	1.5114	$2,275
Unmetered Scattered Load		kWh	14,887	0.005	$74
Total					**$404,649**

Transmission - Connection		Volume			
Class per Load Forecast RPP		**Metric**		**2012**	
Residential		kWh	36,670,298	0.0013	$47,671
General Service < 50 kW		kWh	13,635,988	0.0011	$15,000
General Service 50 to 4,999 kW		kW	66081	0.4581	$30,272
Street Lighting		kW	1505	0.3542	$533
Unmetered Scattered Load		kWh	14,887	0.0011	$16
Total					**$93,492**

Wholesale Market Service		Volume			
Class per Load Forecast RPP		**Metric**		**2012**	
Residential		kWh	36,670,298	0.0052	$190,686
General Service < 50 kW		kWh	13,635,988	0.0052	$70,907
General Service 50 to 4,999 kW		kWh	28514994	0.0052	$148,278
Street Lighting		kWh	543987.37	0.0052	$2,829
Unmetered Scattered Load		kWh	14,887	0.0052	$77
Total					**$412,777**

Rural Rate Assistance		Volume			
Class per Load Forecast RPP		**Metric**		**2012**	
Residential		kWh	36,670,298	0.0011	$40,337
General Service < 50 kW		kWh	13,635,988	0.0011	$15,000
General Service 50 to 4,999 kW		kWh	28514994	0.0011	$31,366
Street Lighting		kWh	543987.37	0.0011	$598
Unmetered Scattered Load		kWh	14,887	0.0011	$16
Total					**$87,318**

Low Voltage Charges		Volume			
Class per Load Forecast RPP		**Metric**		**2012**	
Residential		kWh	33,651,737	0.003	$100,955
General Service < 50 kW		kWh	12,513,525	0.0027	$33,787
General Service 50 to 4,999 kW		kW	66081	1.1187	$73,925
Street Lighting		kW	1505	0.8534	$1,284
Unmetered Scattered Load		kWh	13,662	0.0027	$37
Total					**$209,988**

	2012
4705-Power Purchased	$6,350,558
4708-Charges-WMS	$412,777
4714-Charges-NW	$404,649
4716-Charges-CN	$93,492
4730-Rural Rate Assistance	$87,318
4750-LV Charges	$209,988
Total	**$7,558,781**

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	63,706	9%
Street Lighting	499,759	1,507	2%
Unmetered Scattered Load	11,962		100%
Total	**73,270,262**	**65,213**	

Electricity - Commodity RPP Class per Load Forecast RPP	2013 Forecasted	2013 Loss 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 Class per Load Forecast RPP	2013 Forecasted	2013 Loss 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 Class per Load Forecast RPP		Volume 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	63,706	2.3692	$150,932
Street Lighting		kW	1,507	1.7868	$2,692
Unmetered Scattered Load		kWh	13,035	0.0059	$77
Total					**$482,007**

Transmission - Connection Class per Load Forecast RPP		Volume 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	63,706	0.5163	$32,891
Street Lighting		kW	1,507	0.3992	$601
Unmetered Scattered Load		kWh	13,035	0.0012	$16
Total					**$107,066**

Wholesale Market Service Class per Load Forecast RPP		Volume Metric	2013		
Residential		kWh	38,117,996	0.0052	$198,214
General Service < 50 kW		kWh	13,650,651	0.0052	$70,983
General Service 50 to 4,999 kW		kWh	27,516,337	0.0052	$143,085
Street Lighting		kWh	544,587	0.0052	$2,832
Unmetered Scattered Load		kWh	13,035	0.0052	$68
Total					**$415,182**

Rural Rate Assistance Class per Load Forecast RPP		Volume Metric	2013		
Residential		kWh	38,117,996	0.0011	$41,930
General Service < 50 kW		kWh	13,650,651	0.0011	$15,016
General Service 50 to 4,999 kW		kWh	27,516,337	0.0011	$30,268
Street Lighting		kWh	544,587	0.0011	$599
Unmetered Scattered Load		kWh	13,035	0.0011	$14
Total					**$87,827**

Low Voltage Charges Class per Load Forecast RPP		Volume Metric	2013		
Residential		kWh	34,980,266	0.003436	$120,182
General Service < 50 kW		kWh	12,526,981	0.00307	$38,461
General Service 50 to 4,999 kW		kW	63,706	1.4169	$90,265
Street Lighting		kW	1,507	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	$415,182
4714-Charges-NW	$482,007
4716-Charges-CN	$107,066
4730-Rural Rate Assistance	$87,827
4750-LV Charges	$250,381
Total	**$7,802,913**

Summary of Changes as a Result of Modifying Capitalization and Depreciation Policy

"Modified" CGAAP (MCGAAP)

As previously discussed, SLHI will be taking the additional year deferral for adoption of International Financial Reporting Standards (IFRS) to 2014. For the 2012 fiscal year, SLHI amended its capitalization policies and procedures to be more in line with IFRS and refers to this as Modified Canadian Generally Accepted Accounting Principles ("MCGAAP"). The conversion from Canadian Generally Accepted Accounting Principles, CGAAP to MCGAAP has resulted in a number of changes to SLHI's accounting for Plant Property and Equipment (PP&E).

Impact on Fixed Assets

Componentization and Amortization

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of its useful lives, amortization methods and residual values on an annual basis.

SLHI has reviewed the useful life of its assets with the aid of the Kinectrics report. Exhibit 4, Tab 4, Schedule 2 outlines the amortization expense based on the new useful lives of the assets.

SLHI has restated its continuity statements for the 2012 Bridge year and the 2013 Test year to include these changes.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. SLHI will continue to use the Cost Model to measure PP&E.

Table 2.50: Continuity Statement – 2012 Bridge Year (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	$ 52,240		$ 81,285	$ 4,805	$ 39,701		$ 44,506	$ 36,779
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	$ 103,422		$ 3,576,896	$ 1,186,272	$ 54,541		$ 1,240,813	$ 2,336,083
47	1835	Overhead Conductors & Devices		$ 1,079,982	$ 25,855		$ 1,105,837	$ 474,889	$ 18,068		$ 492,957	$ 612,880
47	1840	Underground Conduit		$ 173,392	$ 5,000		$ 178,392	$ 68,108	$ 2,392		$ 70,500	$ 107,892
47	1845	Underground Conductors & Devices		$ 887,702	$ 26,248		$ 913,950	$ 305,490	$ 16,981		$ 322,471	$ 591,479
47	1850	Line Transformers		$ 1,607,741	$ 46,948		$ 1,654,689	$ 587,436	$ 30,345		$ 617,781	$ 1,036,908
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 454,082	$ 3,890	-$ 294,462	$ 163,510	$ 126,510	$ 11,733	-$ 112,869	$ 25,374	$ 138,136
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	-$ 1,295	$ 22,237	$ 8,429	$ 1,611	-$ 1,295	$ 8,745	$ 13,492
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	$ 13,823	-$ 1,519	$ 41,287	$ 27,598
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 347,546	$ 89,116		$ 436,662	$ 312,619	$ 9,482		$ 322,101	$ 114,561
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	$ 22,930		$ 90,141	$ 51,258	$ 7,702		$ 58,960	$ 31,181
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			$ 37,334	$ 30,354	$ 1,534		$ 31,888	$ 5,446
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	$ 2,000		$ 29,688	$ 20,977	$ 1,233		$ 22,210	$ 7,478
47	1995	Contributions & Grants		-$ 891,191	-$ 92,000		-$ 983,191	-$ 209,723	-$ 22,161		-$ 231,884	-$ 751,307
WIP		Work In Progress		$ 20,502	$ 2,109		$ 22,611	$ -			$ -	$ 22,611
		Total		**$ 7,704,378**	**$ 970,941**	**-$ 297,510**	**$ 8,377,809**	**$ 3,232,145**	**$ 349,497**	**-$ 115,683**	**$ 3,465,959**	**$ 4,904,372**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 13,334
Tools/Sentinel Lights	$ 11,556
Net Depreciation	$ 324,607

Table 2.51: Continuity Statement – 2013 Test Year (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)		$ 81,285	$ 1,000		$ 82,285	$ 44,506	$ 15,607		$ 60,113	$ 22,172
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		$ 3,576,896	$ 49,073		$ 3,625,969	$ 1,240,813	$ 70,114		$ 1,310,927	$ 2,315,042
47	1835	Overhead Conductors & Devices		$ 1,105,837	$ 12,268		$ 1,118,105	$ 492,957	$ 18,508		$ 511,465	$ 606,640
47	1840	Underground Conduit		$ 178,392	$ 5,000		$ 183,392	$ 70,500	$ 2,850		$ 73,350	$ 110,042
47	1845	Underground Conductors & Devices		$ 913,950	$ 89,152		$ 1,003,102	$ 322,471	$ 21,847		$ 344,318	$ 658,784
47	1850	Line Transformers		$ 1,654,689	$ 59,767		$ 1,714,456	$ 617,781	$ 37,104		$ 654,885	$ 1,059,571
47	1855	Services (Overhead & Underground)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters		$ 163,510			$ 163,510	$ 25,374	$ 12,035		$ 37,409	$ 126,101
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)		$ 22,237			$ 22,237	$ 8,745	$ 1,851		$ 10,596	$ 11,641
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	$ 41,287	$ 9,830		$ 51,117	$ 19,768
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment(8 years)		$ 436,662			$ 436,662	$ 322,101	$ 19,693		$ 341,794	$ 94,868
10	1930	Transportation Equipment(5 years)		$ 90,317			$ 90,317	$ 78,365	$ 6,237		$ 84,602	$ 5,715
8	1940	Tools, Shop & Garage Equipment		$ 90,141	$ 5,000		$ 95,141	$ 58,960	$ 5,519		$ 64,479	$ 30,662
8	1945	Measurement & Testing Equipment		$ 12,694	$ 7,000		$ 19,694	$ 10,561	$ 1,643		$ 12,204	$ 7,490
8	1950	Power Operated Equipment		$ 136,522	$ 86,000		$ 222,522	$ 116,965	$ 14,662		$ 131,627	$ 90,895
8	1955	Communications Equipment		$ 37,334			$ 37,334	$ 31,888	$ 1,504		$ 33,392	$ 3,942
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		$ 29,688	$ 2,000		$ 31,688	$ 22,210	$ 1,491		$ 23,701	$ 7,987
47	1995	Contributions & Grants		-$ 983,191	-$ 92,000		-$ 1,075,191	-$ 231,884	-$ 31,517		-$ 263,401	-$ 811,790
WIP		Work In Progress		$ 22,611			$ 22,611	$ -			$ -	$ 22,611
		Total		**$ 8,377,809**	**$ 227,940**	**$ -**	**$ 8,605,749**	**$ 3,465,959**	**$ 255,875**	**$ -**	**$ 3,721,834**	**$ 4,875,928**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 34,355
Tools/Sentinel Lights	$ 10,157
Net Depreciation	$ 211,363

Impact on Capitalization of Burdens

Standard IAS 16 – Property, Plant and Equipment (PP&E) states that the cost of an item of PP&E includes those costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where CGAAP allowed for the capitalization of general and administrative overhead, IFRS does not.

SLHI has reviewed the costs included within its burdens to determine which continue to be appropriate expenses to capitalize and which should be removed from the burden and directly expensed as part of OM&A. For 2011 SLHI identified a total of $2,988 that was contained in its burden rates and capitalized. This amount was for Administration wages that were included in capital, but not directly attributed to capital and therefore would be expensed to OM&A under the new capitalization policy. This amount was not included as capital expense as part of the 2012 capital budget as described in Exhibit 2, Tab 3. No amounts were reported for GEA projects. SLHI determined that the overhead costs currently capitalized are directly attributable and will continue to be capitalized under the new capitalization policy. SLHI will continue to use the 35% burden rate related to the capitalization of self constructed assets consistent with past practice.

Exhibit 4, Tab 4, Schedule 1 provides a detailed breakdown of these expenses and how they will impact OM&A.

Impact on Rate Base

Table 2.52 below provides a comparison of rate base between CGAAP and MCGAAP for the 2012 Bridge Year. The change in net book value has been described above. The working capital allowance has increased under MCGAAP as a result of increased operating expenses, stemming from the removal of expenses from items previously capitalized under CGAAP such as non-directly attributed labour and non major equipment.

Table 2.52: 2012 Bridge CGAAP vs 2012 Bridge MCGAAP

Description	2012 Bridge (CGAAP)	2012 Bridge (MCGAAP)
Gross Fixed Assets	8,359,620	8,348,121
Accumulated Depreciation	3,561,611	3,443,746
Net Book Value	4,798,009	4,904,375
Average Net Book Value	4,631,767	4,684,949
Working Capital Expenses	9,107,026	9,156,801
Working Capital Allowance (13%)	1,183,913	1,190,384
Rate Base	5,815,680	5,875,333

A detailed calculation of the Working Capital Allowance is provided below in table 2.53.

Table 2.53 - Detailed Calculation of Working Capital Allowance

	2013 Test (MCGAAP)
Distribution Expenses - Operations	628,363
Distribution Expenses - Maintenance	196,645
Billing and Collecting	316,965
Administrative & General Expenses	407,460
Taxes Other than Income Taxes	4,986
Total Eligible Distribution Expenses	**1,554,419**
Power Supply Expenses	7,802,913
Total Working Capital Expenses	**9,357,332**
Working Capital Allowance	**1,216,453**
Working Capital Allowance %	**13%**

In the Board's letter dated July 17, 2012, regarding Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013, the Board approved a new variance Account 1576, Accounting Changes Under CGAAP. This variance account is to be used by distributors to record the financial differences arising as a result of the election to implement regulatory accounting policy changes for depreciation expense and capitalization policies effective on January 1, 2012. SLHI has calculated the variance in table 2.54 below following the guidance found in the Board's July 2012 Frequently Asked Questions, question Q2 and Appendix B.

Table 2.54: Variance Account 1576 - in relation to PP&E Changes under CGAAP			
		2011	**2012**
	Basis of Rates	**IRM**	**IRM**
	Forecast vs Actual Used in COS Application	**Actual**	**Forecast**
PP&E Values Assuming "Previous" CGAAP Accounting Policies Continued			
	Opening net PP&E	4,525,710	4,465,522
	Additions	242,585	712,618
	Depreciation (25 years straight line)	-302,773	-372,656
	Closing net PP&E	4,465,522	4,805,484
PP&E Values Assuming Accounting Changes under CGAAP in 2012			
	Opening net PP&E	4,525,710	4,465,522
	Additions	242,585	671,431
	Depreciation (40, 45, 50 years straight line)	-302,773	-232,581
	Closing net PP&E	4,465,522	4,904,372
Difference in Closing net PP&E, "Previous" CGAAP vs "Modified" CGAAP		0	-98,888
Variance Account 1576			
	Opening Balance		98,888
	Amount added annually		
	Closing Balance in deferral account		**98,888**
Journal Entry to record Variance		Debit	Credit
2012	OEB Account 4305(Regulatory Debit)	98,888	
	OEB Account 1576(Accounting Changes under CGAAP)		98,888
	To record differences arising from CGAAP accounting Changes		

SLHI requests the amount of $98,888 to be refunded to ratepayers through an adjustment to depreciation expense over four years. Therefore the adjustment will be $24,722 credit to depreciation expense beginning 2013 until 2016.

GREEN ENERGY PLAN – FUNDING ADDER

SLHI has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix 2-B. The OPA provided a Letter of Comment which has been provided in Appendix 2-C. As part of its plan SLHI did not identify any capital spending requirements. Therefore SLHI is not requesting a funding adder to be included in its rates.

APPENDIX 2-A

Asset Management Plan

Sioux Lookout Hydro Inc. Asset Management Plan

Prepared by:

Automated Solutions International Inc. - Peter Krotky, P.Eng.

Support by:

Sioux Lookout Hydro Inc. - Deanne Kulchyski, President

December 2012

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1.0 Introduction

This document outlines the Sioux Lookout Hydro Inc. (SLHI) Asset Management Plan for the period 2012 to 2016. The report also identifies recommendations to improve on the available asset data and potential to implement a more structured and analytical asset management strategy. This report will focus on asset inspection and maintenance, capital expenditure planning and the required supporting information management systems.

In developing this asset management plan, the following factors were considered:

- available asset inventory
- asset condition based on the current inspection process, and
- current capital expense programs, as identified by SLHI staff

Observations for improvements in inspection, data collection, supporting systems and related asset management processes were also made.

Sioux Lookout Hydro Inc. provides electricity delivery and services to the Municipality of Sioux Lookout. The total municipal population served is 5,336 with a total service area of 536 square kilometres. The municipality includes the communities of Sioux Lookout and Hudson which are mature areas. Outside of these two communities are large rural areas which comprise 530 square kilometres or most of the municipality. The system consists of over 282 kilometres of primary conductor, both overhead and underground and more than 854 distribution transformers, supported by 2,927 poles. Sioux Lookout Hydro does not own any stations.

SLHI operates from the Municipality of Sioux Lookout. SLHI does not host any utilities and does not have any embedded utilities within its service area. SLHI itself is embedded within Hydro One.

The current SLHI system was primarily rebuilt in the 1980's and 1990's. This rebuild upgraded the voltage of the system from 4.16kV to 14.4kV. Although some pockets of single phase 7.2kV remain, this system will not be expanded.

Table 1 below shows the most recent five-year Customer Statistics, showing stability and maturity in the municipality. The following observations can be made:

- Over the past five years the number of customers serviced by SLHI has been very stable with very little year to year change.

- The large drop in kWh after 2007 can be attributed to the closing of the Hudson Saw mill in December of that year. This mill operated for a few months during 2008 and 2010 but has not remained operational.
  The decrease in line losses for 2011 can be attributed to the change in methodology by which the data was collected and processed. During the period in question smart meters allowed for more accurate read dates and consumption numbers. This coupled with a modification to the unbilled revenue calculation process in 2011 is most likely responsible for this change. This may be confirmed when the line losses for 2012 become available.

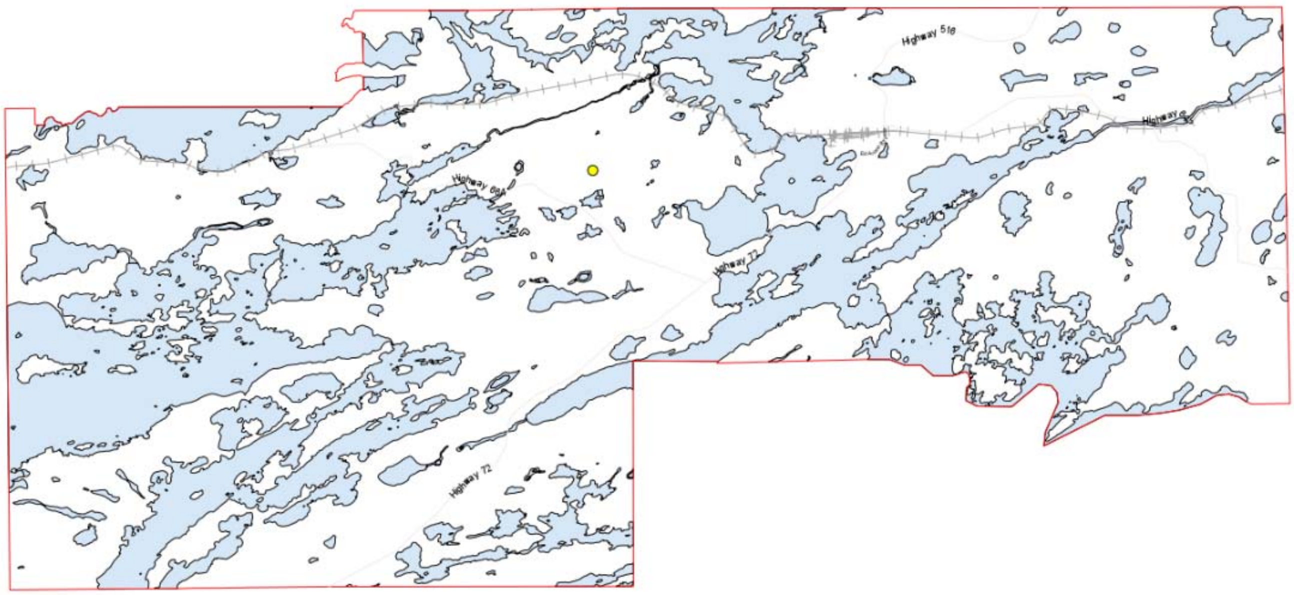


Figure 1 - Sioux Lookout Hydro Inc. Service Areas

Table 1 – SLHI General Statistics as of December 31, 2011

	2007	2008	2009	2010	2011
Population Served	**5,336**	**5,336**	**5,336**	**5,336**	**5,336**
Municipal Population	5,336	5,336	5,336	5,336	5,336
Seasonal Population	0	0	0	0	0
Total Customers	**2,754**	**2,734**	**2,735**	**2,754**	**2,750**
Residential Customers	2,310	2,302	2,296	2,312	2,309
General Service <50 kW Customers	403	392	392	394	393
General Service >50 kW Customers	41	40	39	48	48
Total Street Light Connections	533	532	534	532	532
Total USL customers	**0**	**0**	**13**	**9**	**4**
Total Service Area (km^2)	**536**	**536**	**536**	**536**	**536**
Rural Service Area (km^2)	530	530	530	530	530
Urban Service Area (km^2)	6	6	6	6	6
Total kWh sold (excluding losses)	89,846,017	77,324,320	71,778,509	70,415,620	72,931,754
Total Distribution Losses (kWh)	4,038,863	4,543,155	4,238,120	4,304,224	3,493,100
Total kWh Purchased	**93,884,880**	**81,867,475**	**76,016,629**	**74,719,842**	**76,399,313**
Winter Peak (kW)	22,552	18,091	18,326	17,859	18,704
Summer Peak (kW)	14,949	11,853	11,160	11,303	10,767
Average Peak (kW)	15,505	13,292	12,426	12,538	12,177

The capital expense program presented later in this document consists of projects driven by factors such as safety, system reliability, customer demand and system loss reduction. SLHI will be developing a capital expense model based on a set of consistent criteria with weight factors that will be applied. Direction was provided by the SLHI Board of Directors, the Municipality Official Plan and developers. The web links below provide a reference to the official plan documents. Each project identified by SLHI is supported by the appropriate documentation in Section 9.

The official plan for the communities served by SLHI are linked here:

http://www.siouxlookout.ca/files/OP%20Dec%202-2011%20with%20mapping.pdf

In addition, the Ministry of Energy and Infrastructure has a strategic vision for growth for the SLHI area and can be found here: https://www.placestogrow.ca/images/pdfs/GPNO-final.pdf

This Asset Management Plan is a 'living document' and will be reviewed on an on-going basis.

2.0 SLHI Distribution System Overview

The SLHI Asset Management Plan primarily focuses on the assets summarized in the table below. These assets represent the major equipment as defined by the *ESA Equipment and Material Guideline*. The subsequent sections of the report provide further detail and assessment of each asset type. Table 2 also identifies some key system indicators.

Table 2 - SLHI System Summary Overview 2011

System Peak (kW – annual average)	18,704
Service Area (sq. km)	536
Total Customers	2,750
GS > 50	48
GS<50	393
Residential	2,309
Smart Meters (to date)	2,706
PME's	5
Poles	2,927
Primary Lines (km)	282
Overhead	248
Underground	34
Submarine	2.6
Transformers (units)	854
OH	759
UG	95
Switches	52

2.1 Inspection

Sioux Lookout Hydro Inc. has implemented and follows inspection and maintenance procedures, in accordance with the Distribution System Code (DSC), Regulation 22/04, Sections 4 and 5, and ESA Guidelines.

These procedures were implemented in February 2007 and are defined by the document entitled “Sioux Lookout Hydro Inc. Policy & Procedure for Overhead & Underground Maintenance”. This document contains three supporting tables, namely:

1. Table C-1 Electric Utility System Inspection Cycles (Maximum intervals in Years)
2. Table C-2 Sample Annual Inspection Summary Report
3. Table C-3 Sample Patrol Deficiency Record

For transformer inspection SLHI uses the “Sioux Lookout Hydro Inc. Line Patrol Inspection Checklist-Overhead and Padmount Transformers.”

In addition SLHI uses the “Sioux Lookout Hydro Inc. Hazard Identification Form” when dangerous situations do or could exist. This includes an indication of the appropriate response to any hazard by identifying its priority as High, Low or requiring an outage.

For the purpose of this report, these documents collectively will be referred to as the SLHI Inspection and Maintenance Procedures and are included in Appendix A. These procedures generate a number of forms and checklists which will be referred to as Records.

All line patrols and inspections are documented using the above Records. The asset inspection data and available device information is used to support maintenance activities and capital expense planning. Specific inspection and testing processes are dependent on the asset type.

SLHI recognizes an opportunity to better manage its assets using a longer term plan. The implementation of an asset management system with all data linked to a Geographic Information System will facilitate the interpretation of data and allow for better planning of construction, inspection and maintenance work.

With the implementation of an asset management system, SLHI can correlate asset condition data, asset maintenance and replacement expenditures and the resulting system performance indicators. These systems and their information collaborate and support the experience of SLHI staff.

2.2 Maintenance and Operating Activities

SLHI performs a number of maintenance and operating activities to ensure a safe and reliable operation of the distribution system. These activities are budgeted on an annual basis. The five year plan is presented in Table 11 of Section 9 of this report.

2.2.1 Locates and Connections

SLHI provides locating services for the residents served by SLHI and in response to contractors performing work on and around the SLHI underground system. Table 3 indicates the number of locates per year has been rising over the past five years as a result of an increase in construction activity. The new connection activity is relatively stable – this is indicated by the numbers over the last five years, as shown in Table 3 below.

Service layouts are prepared for any new home construction (in-fill) or service upgrade, commercial or residential, due to the expansions of the loads on existing lots. As indicated by Table 1, the application for new services and service upgrades has been minimal.

Table 3 - Four Year Locates and Connections Summary

	2007	2008	2009	2010	2011
Average Customer Count	2,735	2,749	2,739	2,744	2,748
Number of Locates	58	56	83	83	110
Number of New Connections	29	29	27	27	31

2.2.2 System Performance

SLHI measures system performance indicators in accordance with the Distribution System Code. The following is a summary of the key system performance indicators for the past five years:

Table 4 - Four Year System Performance Summary

	2007	2008	2009	2010	2011
Average Customer Count	2,735	2,749	2,739	2,744	2,748
Including loss of service from Hydro One					
Number of Customer Interruptions	6519	714	897	9,798	4,850
Total Customer Hours of Interruptions	12,066	1,157	888	30,164	21,281
SAIDI	4.41	0.42	0.32	10.99	7.74
SAIFI	2.38	0.26	0.33	3.57	1.77
CAIDI	1.85	1.62	0.99	3.08	4.39
Excluding loss of service from Hydro One					
Number of Customer Interruptions	1,072	714	897	1,538	2,104
Total Customer Hours of Interruptions	1,127	1,157	888	2,464	4,695
SAIDI	0.41	0.42	0.32	0.9	1.71
SAIFI	0.39	0.26	0.33	0.56	0.77
CAIDI	1.05	1.62	0.99	1.6	2.23

Table 4 shows a significant improvement in system performance statistics when loss of service from Hydro One is excluded. SLHI's true system performance is indicated by removing the effect of the supplier's outages. Since SLHI is an embedded utility the have no direct control over the suppliers outages.

The highest number of outages is caused by bird and animal contact with SLHI equipment. Ravens in particular disable many transformers every year. May and June see the largest number of outages as young ravens attempt to use the tops of transformers as flight platforms. SLHI is implementing guards on transformer equipment to mitigate the frequency of these outages and protect wildlife.

SLHI has seen an increase in outages over the last two years. This is attributed to an increase in severity and frequency of storm activities over the same period. When these uncontrollable factors are removed, the reliability indicators show a system which is both reliable and stable with only small fluctuations from year to year.

2.3 **Capital**

It is important that assets are not replaced before the end of their useful life. It is generally accepted in industry that, rather than age, the asset "stress" is a more important factor in determining asset life and an indicator for the required maintenance or replacement of the asset. It therefore stands to reason, that assets under greater stress should be monitored more closely and maintained more than those under less stress. This ensures a wise use of limited capital and maintenance expenditures.

SLHI is in the process of implementing an asset management system, supported by engineering analysis tools, to provide additional information for future asset assessments and determine which assets are under more stress and therefore require replacement or additional maintenance.

3.0 Substations

Sioux Lookout Hydro Inc. does not own or operate any substations. The municipality is supplied by a single Hydro One substation located north of Highway 664 and energized at 14.4kV. The location of this station can be found in Figure 1. This station provides four feeders for the SLHI distribution system. The installed kVA and therefore the relative feeder load is shown in Table 5 and Chart 1. It is worth noting that the table and chart show connected kVA and not actual load. The utilization of each feeder is detailed below:

3.1 Feeder 1 (F1)

This feeder stretches west from the station to the town of Hudson. Hudson represents most of the load on this feeder. Some additional load exists between the community and the station where small pockets of residences are found. This feeder also supplies a Hydro One load transfer to Frenchman's Head, a small community across the lake from Hudson. Submarine cable is used for this load transfer. This is the most lightly loaded feeder currently in service.

3.2 Feeder 2 (F2)

This feeder extends south-east of the station to provide power for the south half of Sioux Lookout including the south shore of the lake. The blue phase of this feeder branches south into rural areas on Highway 72. This section consists of a large number of single phase 25kVA and 50kVA transformers. These transformers are lightly loaded. Based on experience, phase balancing and conductor loading are within acceptable levels. This feeder makes up approximately 37% of the system load.

3.3 Feeder 3 (F3)

This feeder travels east of the station to supply the northern part of Sioux Lookout. This stretch includes most of the heavier loads in the municipality, including the airport and hospital. This is shown in Table 5 and Chart 1. The blue phase of this feeder continues east of the town to supply a rural area on Highway 642 and a load transfer for Hydro One. The phase loading on Feeder 3 has recently been balanced.

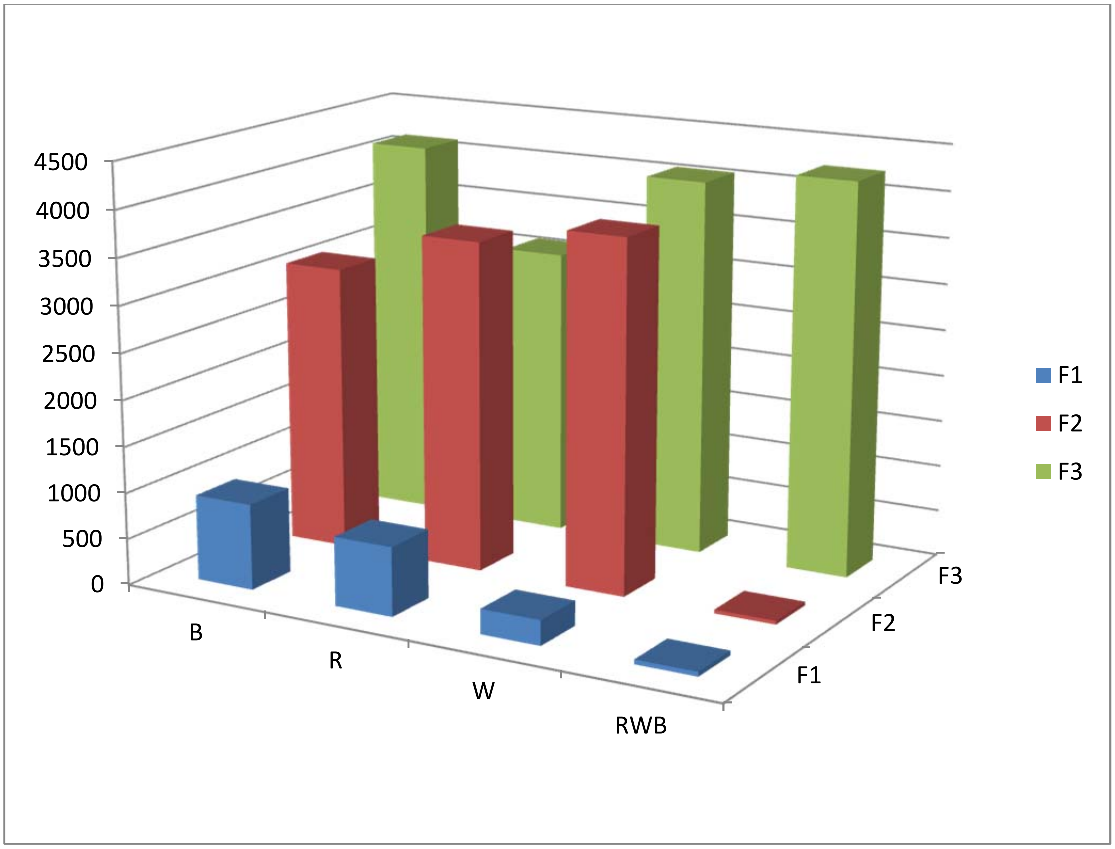
3.4 Feeder 4 (F4)

This feeder does not currently carry any load. Previously it had been a dedicated feeder for the Hudson Saw Mill. With the mill's closure, the load has been removed.

Table 5 - SLHI Installed kVA by Phase by Feeder

Phase	F1	F2	F3	Total
B	925	3,085	4,136	8,146
R	745	3,567.5	3,109	7,421.5
W	270	3,799.5	4,076	8,145.5
RWB	50	40	4,249	4,339
Total	**1,990**	**10,492**	**15,570**	**28,052**
% Total	**7%**	**37%**	**56%**	

Chart 1 - SLHI Installed kVA by Phase by Feeder



The low population density throughout most of SLHI's distribution system does not allow for effective switching of loads between all three active feeders. F2 and F3 are interconnected in the southern half of the community of Sioux Lookout. This provides switching between feeders in the more densely populated community. In the rural areas, where only a single phase is required to supply long stretches of light load it is not practical or cost effective, at this time, to provide switching between feeders.

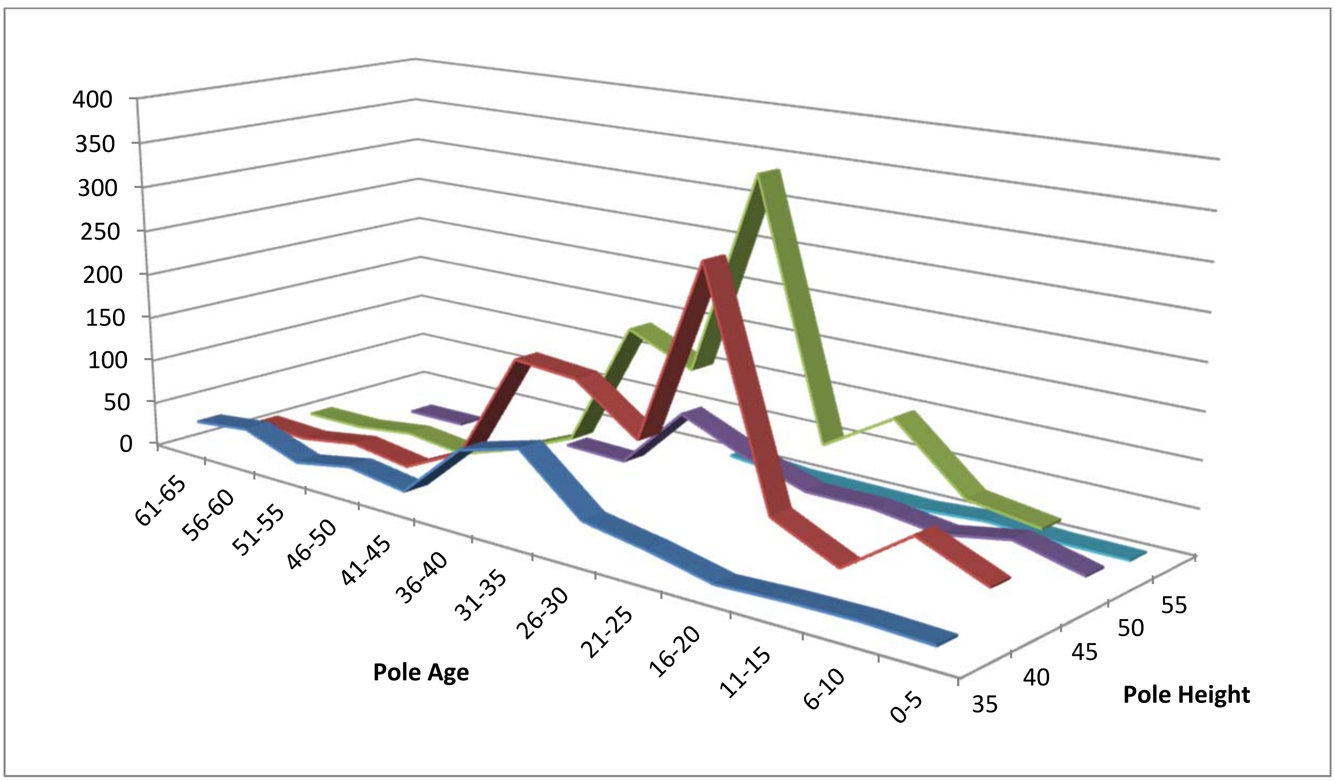
4.0 Poles

The SLHI overhead distribution system is supported by approximately 2,930 poles, primarily wood. The table below provides a height and age distribution, based on available information. Visual inspection of poles is conducted in accordance with the Distribution System Code.

Table 6 - SLHI Poles by Height and Age

	Pole Height (feet)					
Pole age (years)	35	40	45	50	55	Grand Total
61-65	30	10	2			**42**
56-60	37	7	2	2		**48**
51-55	15	17	10	2	1	**45**
46-50	27	7	2			**36**
41-45	17	39	24	9	1	**40**
36-40	79	158	53	7		**297**
31-35	97	152	188	77	10	**524**
26-30	39	103	159	47	3	**351**
21-25	27	300	373	24	2	**726**
16-20	11	58	111	24	1	**205**
11-15	14	27	154	14	6	**212**
6-10	15	76	90	27	2	**216**
0-5	12	44	79	8	1	**144**
Grand Total	**420**	**995**	**1,247**	**241**	**27**	**2,930**

Chart 2 - SLHI Poles by Height and Age



The majority of the SLHI system was rebuilt from 1970 through the late 1990's. The sharp increase in pole installations during this period can be seen in Table 6 and Chart 2. Less than 10% of the poles currently installed on the SLHI system originate prior to this period. The information in Table 6 and Chart 2 show a clear shift in SLHI's design standards to 40' and 45' poles. This rebuilt will result in a lower than normal pole replacement in the short term.

With the implementation of an asset management system in 2012, supported by engineering analysis tools, SLHI will be able to determine which poles are under more stress and therefore require more frequent inspection, testing and/or maintenance and ultimately replacement.

Currently, poles that are identified through reports from line patrols, as a potential health and safety hazard to the public and staff, are replaced on a high priority basis. Prioritization of pole replacements is based on the number of customers that will be interrupted if a pole fails. This places poles carrying three phase primary circuits as the highest priority. Also any road authority or private development projects may require pole replacement not specifically identified by inspection and testing. SLHI is working towards a pole replacement cycle of no less than 40 years, in line with industry norms. Poles older than 40 years that are lightly loaded (low stress) and in good condition will be maintained in service.

It is also recognized that an appropriate replacement program must consider the relationship of the pole asset with other assets in its proximity and within the network system. This activity and the corresponding financial requirements are summarized in Table 10 of Section 9.

4.1 Inspection

Line patrols, conducted in accordance with the requirements of the Distribution System Code and SLHI Inspection and Maintenance Procedures, include a visual inspection of poles for the following:

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Woodpeckers may cause severe damage to poles to the point where the poles must be replaced prior to the end of their expected life. SLHI is aware of this reality in Northern Ontario and identifies woodpecker damage during patrols. Where woodpecker damage is minimal and may be mitigated by repair procedures, the pole may not be immediately replaced.

4.2 Pole Capital

SLHI currently does not rely on pole testing to determine the need for pole replacement. As mentioned previously other factors are taken into consideration when planning for future pole replacement.

The stress placed on a pole is important when considering its lifespan; generally the greater the stress the shorter the lifespan. The stress increases with equipment, such as transformers or utilization, such as dead ended or line angle installations. It is therefore important that they be more closely monitored.

Due to the system rebuild completed in the 1990's the proposed five year plan targets approximately 1% of the pole population for replacement annually. As these poles age, the number of poles to be replaced annually is expected to increase and approach industry norms.

5.0 Transformers

The SLHI distribution system consists of 759 polemount and 95 padmount transformers. Current data available includes the size, type, manufacturer, serial number and manufactured year. The following tables show a summary of the overhead and underground single phase and three phase transformer data.

Table 7 - Single Phase Polemount Transformer Summary

	Decade of Transformer Purchase						
Transformer kVA	1960s	1970s	1980s	1990s	2000s	2010s	Total
3						1	1
5			1				1
10		8	18	14			40
15		1		10			11
25	1	39	133	97	65	12	347
37.5		1					1
50		28	134	45	40	4	251
75			16		3		19
100		6	58	6	2		72
167			2	8	3	1	14
Total	**1**	**83**	**361**	**180**	**113**	**18**	**756**

Table 8 - Single Phase Padmount Transformer Summary

	Decade of Transformer Purchase					
Transformer kVA	1970s	1980s	1990s	2000s	2010s	Total
25		12	17	2		31
37.5				3		3
50	5	3	7		1	16
75		3	3	2		8
100		2	5			7
167		1	1			2
Total	**5**	**21**	**33**	**7**	**1**	**67**

Table 9 - Three Phase Padmount Transformer Summary

	Decade of Transformer Purchase					
Transformer kVA	1970s	1980s	1990s	2000s	2010s	Total
75		1	1	1		3
150		1				1
225			2			2
300	1	3	3	6		13
500			2	2		4
750		1	1	2		4
1000				1		1
Total	**1**	**6**	**9**	**12**		**28**

Chart 3 - Single Phase Polemount Transformer Summary

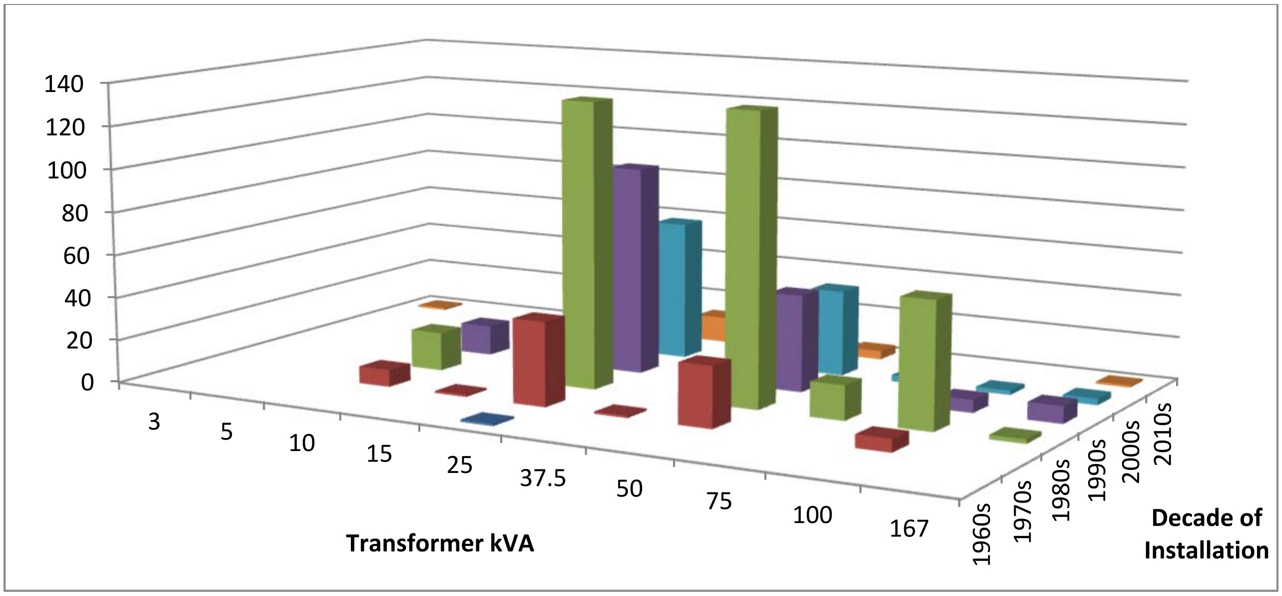


Chart 4 - Single Phase Padmount Transformer Summary

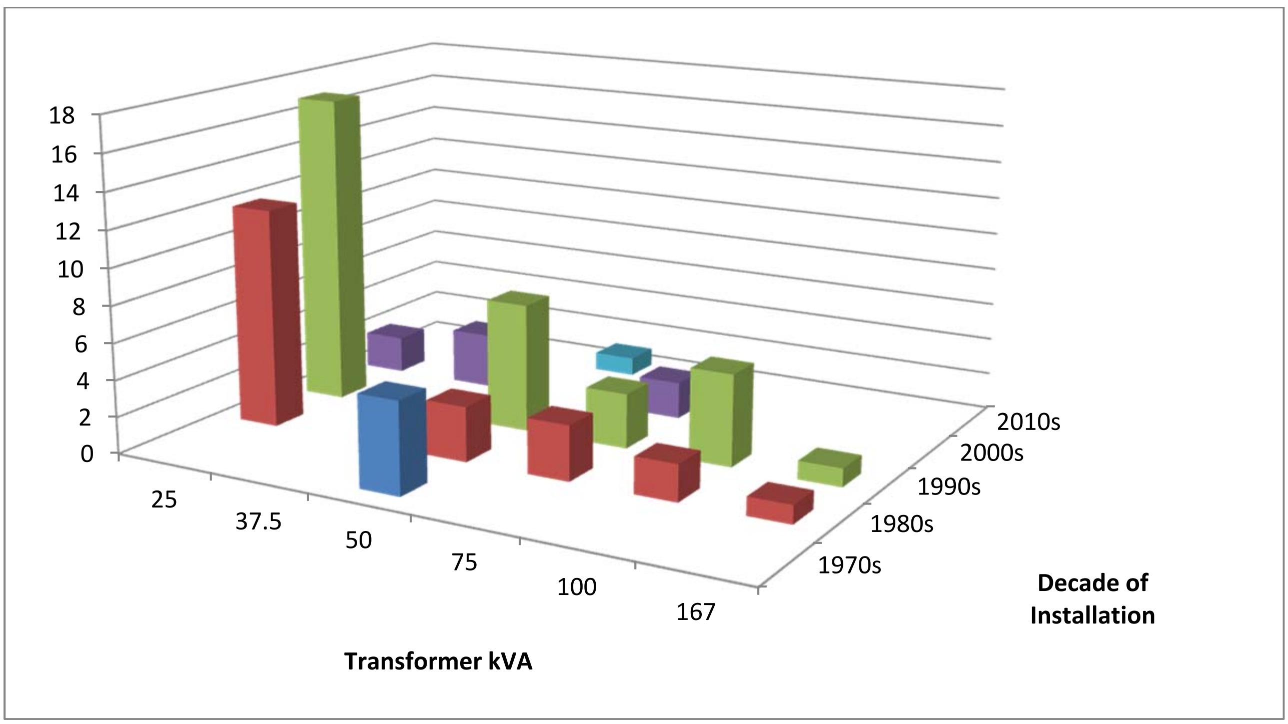
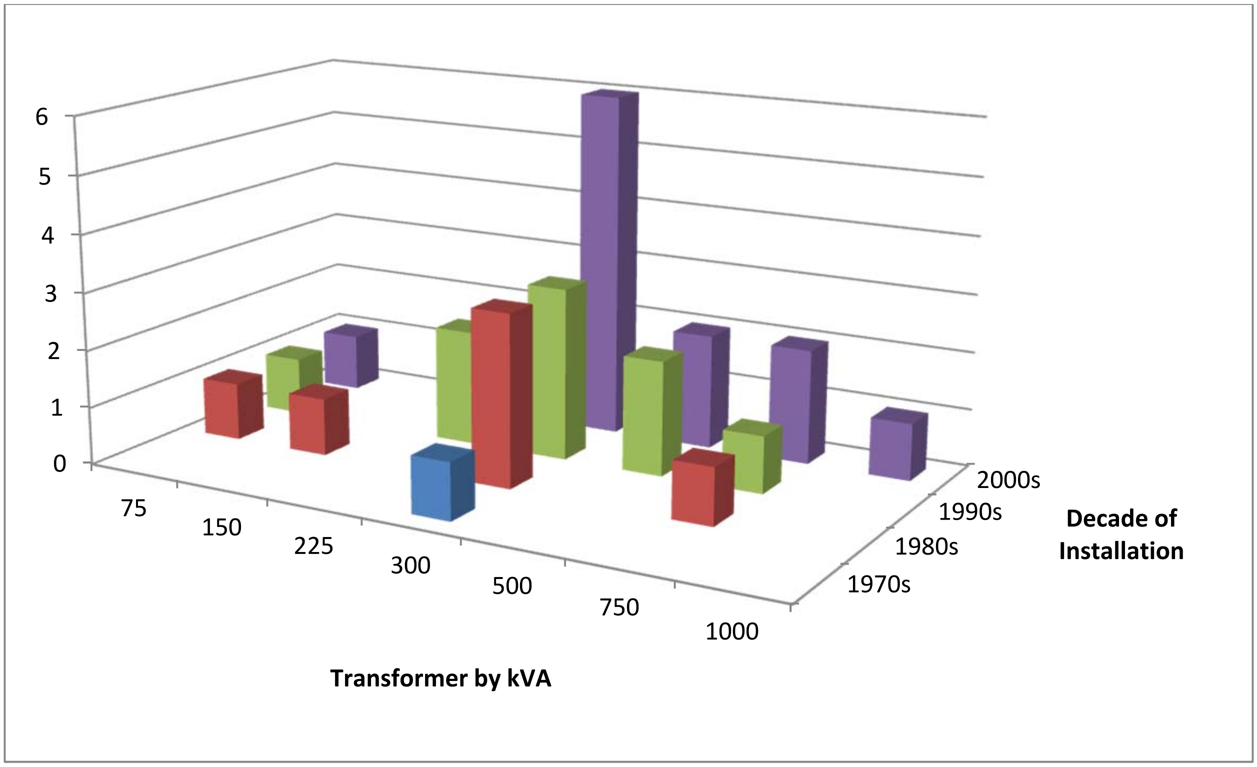


Chart 5 - Three Phase Padmount Transformer Summary



The data provided in the charts above demonstrates the rebuild which took place during the 1980s and 1990s.

During the rebuild period SLHI focused on the rebuild of the urban area primarily in the 1980s resulting in the installation of larger kVA transformers. As the rebuild moved to the rural areas in the 1990s a larger number of smaller kVA transformers was installed. This is reflected in Table 7 and Chart 3. The 25kVA transformers are more prevalent in the rural areas of the SLHI system such as on Feeder F2. The 50kVA transformers form the backbone of the F3 feeder which supplies power to the town itself.

Since the 1970s, underground construction is the preferred design standard for residential subdivision and commercial developments. This resulted in an increase in the use of single phase padmount transformers for residential subdivisions as seen in Table 8 and Chart 4. The SLHI population of three phase padmount transformers has increased during the same period, due to commercial development drivers. This trend is shown in Table 9 and Chart 5.

Design practices of utilities, particularly in the past 25 years, have been to substantially oversize transformers for the average load required to be supplied. A typical utility average transformer utilization factor is between 20-35%.

Implementation of the asset management system has improved the level of detail maintained on each transformer. The system will also be integrated with the existing SLHI customer information. This together with the connectivity model and weather data, will allow SLHI to determine which transformers are under more stress and therefore require closer monitoring or maintenance and an appropriate replacement program. The additional data will also allow SLHI to determine opportunities to consolidate transformer sites, primarily in the urban area, thereby reducing transformer losses.

5.1 Inspection

SLHI visually inspects transformers every three years under the Overhead Visual Inspection and Underground Visual Inspection Programs and record and follow-up on any complaints received from customers. The inspection of transformers is in accordance with the requirements of the Distribution System Code and SLHI Inspection and Maintenance Procedures, includes:

- Paint condition and corrosion
- Placement on Pad or Vault
- Check for lock and penta bolt in place
- Grading changes
- Access changes (Shrubs, trees, etc.)
- Phase indicators and unit numbers match operating map(where used)
- Leaking oil
- Flashed or cracked insulators
- Pad mounted – lid damage, missing bolts, cabinet damage, public security lock damage
- Contamination/discolouration of bushings
- Ground lead attachment
- Bird or animal nests
- Vines or brush growth interference
- Evidence of bushing flashover
- Accessibility compromised
- Vegetation Right of Way
- Unapproved/unsafe occupation or secondary use
- Cable connections
- Ground connections
- Nomenclature
- General Condition

5.2 Transformer Capital

A number of units are replaced annually, as part of projects driven by ongoing system improvements. With the addition of a transformer load management system, SLHI will have improved information to identify overloaded or stressed transformers requiring replacement.

Replacement of transformers is completed both as a part of maintenance and capital projects.

Due to the system rebuild completed in the 1990's the proposed five year plan targets approximately 1% of the transformer population for replacement annually. As these transformers age, the number of transformers to be replaced annually is expected to increase and approach industry norms. This activity and the financial requirements are summarized in Table 10 of Section 9.

SLHI recently completed a multi-year transformer PCB testing program. The results did not identify any transformers for cleaning or replacement.

6.0 Switches and Protection

SLHI relies upon 52 solid blade switches for control of its 14.4kV system. These switches are placed to allow for the isolation of any problems occurring on the system. In addition SLHI has a number of fuses for sectionalizing and downstream protection coordination of the system.

6.1 **Reclosers**

There are currently four reclosers installed on the SLH system. Three are used to protect long single phase branches from unnecessary outages on isolated lines. One recloser protects a three phase tap.

6.2 **Fusing**

In accordance with good utility practice SLHI fuses all major junctions and taps feeding from main feeders.

Due to the large low density rural service area included in the SLHI system, long single phase branches extend away from the main communities. These branches are fused wherever they split into two or more lines to ensure that only a small number of customers will be affected should any of these branches experience a fault.

SLHI is currently testing the effectiveness of the S&C Trip Saver device. A Trip saver has been installed at the Junction of Highways 72 and 642. The trip saver may act as an alternative to larger more expensive reclosers making them more viable for the large low density areas of the SLHI system. If outages are reduced significantly more may be purchased to reduce the need for fuse replacements elsewhere.

6.3 **Inspection and Maintenance**

Visual inspections are carried out on all switches as part of the Overhead Visual Inspection Program. These visual inspections occur once every three years in accordance with the requirements of the Distribution System Code and SLHI Inspection and Maintenance Procedures and include:

- Bent, Broken bushings and cutouts
- Damaged lightning arresters
- Ground wire on arresters unattached

A switch that fails the inspection process would be replaced on a priority basis.

6.4 **Switching and Protection Capital**

All SLHI cutouts are maintained as required by the SLHI Inspection and Maintenance procedures and in accordance with the Distribution System Code.

Using cutout style switches rather than large gang operated switches allows SLHI to keep maintenance costs down as the larger switches require specialized maintenance on a regular basis.

SLHI is considering the installation of a set of reclosers outside of the Hydro One station. This would improve reliability on the long rural feeders which feed the town of Sioux Lookout. Prior to any decision, this option must be studied and is not included in the proposed five year plan.

7.0 Conductor

SLH maintains lightly loaded distribution lines over comparatively long distances throughout its system. Past installation practices have varied which has resulted in a mixture of different conductor sizes throughout the system. This includes six blocks of #2 and #4 copper from First Avenue to Sixth Avenue in the community of Sioux Lookout. At this time all conductors installed are capable of carrying the required load and as such will not be replaced until their end of life.

Current practice is to use a more uniform approach to conductor sizing. For primary circuits SLHI now installs 1/0 ACSR for single phase lines and 3/0 ACSR for three phase lines. Over time these conductors will replace the older more varied sizes.

7.1 Primary

The majority of the SLHI distribution system is operated at 14.4kV and was upgraded in the 1980s from a 4.16kV system to reduce loses, in line with industry practices.

Some portions of the current system were originally owned by Hydro One / Ontario Hydro. This is the reason for the existence of the 7.2kV pockets which exist throughout the system. Where economical, these pockets will be replaced or converted over time to 14.4kV, as other assets in the proximity, such as poles must also be replaced. SLHI is not actively eliminating 7.2kV system, nor will SLHI be investing in any new equipment for the 7.2kV system.

7.2 Secondary

The conductor type used for secondary circuits in the past has varied throughout the SLHI system depending on ownership and year of installation. Hydro One construction practices for secondary and services are different from current SLHI standards. SLHI now uses NS 750 #2 ACSR for 100A services and NS 750 1/0 ACSR for 200A services for any new overhead installations. For underground services, 3/0 cable is used for most applications. However over longer distances 250 MCM may be substituted.

Although the secondary bus is not always replaced when one customer upgrades their service, should a number of customers supplied by the same transformer upgrade, the secondary would be assessed and replaced based on current standards.

7.3 Inspection

Line patrols are conducted annually in accordance with the requirements of the Distribution System Code and SLHI Inspection and Maintenance Procedures. The line patrols include a visual inspection of the following:

Conductors and Cables

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary

Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated (difficult to see)
- Tie wires unraveled

- Ground wire broken or removed
- Ground wire guards removed or broken

General Conditions and Vegetation

- Leaning or broken "danger" trees
- Growth into line of "climbing" plants
- Accessibility compromised
- Vines or bush growth interference (line clearance)
- Bird or animal nests

Vegetation and Right of Way:

- Accessibility compromised
- Grade changes that could expose cable
- Excessive vegetation on right of way

7.3.1 Line Patrol

SLHI patrols its entire distribution system every three years, in accordance with the requirements of the Distribution System Code and SLHI Inspection and Maintenance Procedures. Distribution system line patrols are tracked using the "*Line Patrol Inspection Checklist*".

7.4 **Maintenance**

Due to the extensive wilderness area covered by SLHI lines, tree trimming is consistently one of the largest costs associated with maintaining system reliability. As part of the regular maintenance plan for the conductor assets, SLHI schedules regular tree-trimming activities, as described below.

7.4.1 Overhead System - Tree-Trimming

Vegetation and Right of Way control is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. SLHI distribution area includes some tourist areas and therefore can be sensitive to tree trimming activities. SLHI has a relatively heavy mature tree cover where overhead hydro lines are in the proximity to trees. Tree contact with energized lines can cause the following:

- Interruption of power due to short circuit to ground or between phases
- Damage to conductors, hardware and poles
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles and trees
- Danger of electric shock potential from electricity energizing vegetation

Care must be taken to balance the requirements of customers and stakeholders and safe and reliable operation of the distribution system. In general, the three-phase circuit sections require higher reliability and are therefore trimmed on a more frequent basis than the single-phase circuit sections.

Tree Trimming inspections have been incorporated into the other inspection programs included in this plan and additional checks will be performed by work crews in the areas in which regular work is performed.

SLHI performs line clearing in accordance with the SLHI Line Clearing Program. Maintenance work orders are issued as a result of field observations and inspections. All work is scheduled accordingly.

To mitigate direct contact between trees and distribution assets, SLHI conducts tree trimming in accordance with the SLHI Procedures. Depending on the size, shape and growth aspect of each tree species, the tree trimmers remove sufficient material from the tree to limit the possibility of contact during high wind situations.

All debris is removed and the site is returned to as-found condition. Any pole line damage or anomaly noticed by the tree trimming crew is reported to the Operation Manager of SLHI for remedial action.

7.5 **Conductor Capital**

In a recent report released by ESA, concerns have been raised with the possibility of failure of older small conductors, due to aging, stretching and a general weakening, under certain installation conditions. The report does not identify these conditions; however, it does recommend the elimination of #6 copper as a primary conductor and suggests replacement of other small conductors, such as #4 ACSR and #2 ACSR.

SLHI does not have any #6 copper. Small pockets of #2 and #4 copper can be found, primarily in the Sioux Lookout community. These pockets are lightly loaded and do not require replacement at this time – they will be closely monitored.

8.0 Metering and Monitoring

SLHI currently bills all customers monthly on a schedule. This schedule is divided into cycle routes, each of which have a defined read and bill date. Billing occurs on the Monday of each week.

8.1 Wholesale

Sioux Lookout Hydro receives its power from a single TS location in the center of its territory.

SLHI current possess six primary metering units, which provide metering to large customers.

8.2 Retail Metering

The SLHI customer information is summarized in Table 1. Thunder Bay Hydro utilizes servers located in Thunder Bay and monitors all smart meter Advanced Metering Infrastructure (AMI) and associated information.

8.3 Inspection

All maintenance activities related to meters follow the requirements of Measurement Canada guidelines.

8.4 Implementation

SLHI completed installation of 100% of all required smart meters by December 31 2010. Time of use billing was then scheduled to begin in June of 2011 but was delayed until September of that year.

As of December 31 2011 the number of smart meters attached to the SLHI system has risen to 2,706. To pay for these installations a stand alone application was submitted to the Ontario Energy Board in May of 2012 for final disposition of costs and applied for a Service Meter Incremental Rate Rider (SMIRR) until the upcoming cost of service application.

8.5 Capital

SLHI has prepared a budget that should complement its load growth over the next five years. Refer to Section 9 for details.

9.0 Capital Forecast Plan

SLHI recognizes the need to address the aging assets. With better information in the near future, an appropriate plan for replacement will be prepared. Closer monitoring and coordination with the Municipality and local agencies regarding expansion plans will allow SLHI to better track asset replacement requirements.

The following Table summarizes the 5 year plan:

Table 10 - Capital Expenses

DESCRIPTION	2012	2013	2014	2015	2016
POLES	**$42,935**	**$50,422**	**$72,228**	**$94,532**	**$101,605**
New Construction	$10,195	$3,500	$9,140	$19,100	$17,397
Line Improvements	$32,740	$46,923	$63,088	$75,432	$84,208
POLE MOUNT TRANSFORMER	**$49,224**	**$42,639**	**$53,433**	**$41,830**	**$39,057**
New Construction	$21,395	$21,045	$24,710	$38,090	$35,317
Line Improvements	$27,829	$21,595	$28,723	$3,740	$3,740
OVERHEAD PRIMARY CONDUCTOR	**$4,534**	**$3,039**	**$3,126**	**$69,774**	**$31,012**
New Construction	$2,267	$732	$782	$864	$579
Line Improvements	$2,267	$2,307	$2,345	$68,910	$30,433
OVERHEAD SECONDARY CONDUCTOR	**$13,504**	**$7,880**	**$8,240**	**$3,447**	**$5,471**
New Construction	$8,440	$2,697	$2,943	$0	$0
Line Improvements	$5,064	$5,184	$5,297	$3,447	$5,471
UNDERGROUND TRANSFORMER	**$25,525**	**$17,128**	**$33,111**	**$8,506**	**$8,712**
New Construction	$0	$8,568	$25,103	$8,506	$8,712
Line Improvements	$25,525	$8,559	$8,008	$0	$0
UNDERGROUND PRIMARY CONDUCTOR	**$11,318**	**$13,451**	**$17,152**	**$12,597**	**$6,658**
New Construction	$10,100	$12,748	$3,160	$11,880	$5,940
Line Improvements	$1,218	$703	$13,993	$717	$718
UNDERGROUND SECONDARY CONDUCTOR	**$8,685**	**$8,501**	**$17,685**	**$8,446**	**$4,847**
New Construction	$6,624	$7,468	$10,088	$7,406	$3,806
Line Improvements	$2,061	$1,033	$7,597	$1,039	$1,041
SUBMARINE PRIMARY CONDUCTOR	**$0**	**$72,200**	**$0**	**$0**	**$0**
New Construction	$0	$0	$0	$0	$0
Line Improvements	$0	$72,200	$0	$0	$0
METERS	**$3,360**	**$1,680**	**$3,310**	**$1,869**	**$2,520**
New Construction	$2,856	$1,680	$3,310	$1,869	$2,520
Line Improvements	$504	$0	$0	$0	$0
OTHER ASSETS	**$173,500**	**$101,000**	**$108,000**	**$46,500**	**$81,500**
Vehicles and Equipment	$155,000	$86,000	$30,000	$35,000	$70,000
Tools	$10,000	$12,000	$20,000	$10,000	$10,000
Computer Hardware and Software	$8,500	$3,000	$8,000	$1,500	$1,500
Distributed Generation Assets	$0	$0	$50,000	$0	$0
YEARLY TOTALS	**$332,584**	**$317,941**	**$316,286**	**$287,5011**	**$281,382**

Table 11 - Operation and Maintenance Expenses

DESCRIPTION	2012	2013	2014	2015	2016
Operations O/H Distribution Lines - Labour	$367,580	$364,447	$375,380	$386,641	$398,241
Operations O/H - Supplies And Expenses	$131,054	$132,211	$134,854	$137,551	$140,302
Distribution Pole Maintenance	$41,977	$48,730	$50,172	$51,677	$53,227
Distribution Line Maintenance and Feeder Right-of-away	$60,000	$61,200	$62,424	$63,672	$64,946
Transformer Maintenance	$12,055	$13,774	$14,167	$14,592	$15,030
Meter Maintenance	$13,166	$14,889	$15,305	$15,764	$16,237
Miscellaneous Ops & Maintenance Expense	$51,820	$69,968	$71,328	$72,755	$74,210
YEARLY TOTAL	**$677,652**	**$705,219**	**$723,630**	**$742,653**	**$762,193**

SLHI is able to forecast their needs for 2012 and 2013 with greater accuracy. The following sections describe the works to be completed in more detail.

9.1 Capital Expense 2012 - Details

9.1.1 Distribution Lines Overhead (Act #1830 & 1835)

This account includes Poles, Towers, Fixtures, Conductors and Devices. It covers all the overhead work scheduled to be completed on the 7.2kV and 14.4kV distribution systems.

2012-4 SLHI is upgrading the single Phase circuit on Moose horn road to the 14.4kV system voltage used by the bulk of the system. This will include the installation of eleven new poles in 2012. No new conductor will be strung.	$24,584
2012-2 New Housing development in 2012 will require the installation of five new poles and 300m of new conductor to provide the development with single phase power.	$20,901
2012-1 Pole Replacements will account for four new poles during the later part of 2012.	$8,156
2012-3 General Upgrades to the SLHI system in the later part of 2012 will include the stringing of 300m of new primary conductor and 900m of secondary conductor.	$7,330
Total Budget	**$60,971**

9.1.2 Distribution Lines Underground (Act #1840 & 1845)

Unlike the overhead construction, underground installations are largely dependent on new development throughout the Town. A Developer may forecast on the installation of 100 lots, and only construct 50 because of sales, or they want to construct additional lots at the end of the year for economical reason. The following was made with the best data available at the time.

2012-2 New Housing construction in 2012 will require 200m of both primary and secondary conductor.	$7,229
2012-2 The new 4 plex unit being installed in 2012 will require 100m of primary conductor to be installed.	$3,165
2012-3 General Upgrades to SLHI underground system will require the installation of 60m of underground primary cable and 180m of underground secondary cable.	$3,279
2012-2 To feed the new offices being installed in 2012, 20m of primary conductor will be installed.	$6,329
Sub Total	**$20,002**
Contributed Capital*	**$5,001**
SLHI Total Budget	**$25,003**

*The amount shown as Contributed Capital is based on historical values calculated through Economic Evaluation Model studies.

9.1.3 Distribution Transformers (Act #1850)

This account is similar to the underground distribution account, as its dependent on the activities of Developers. Again our best guess at the time is shown below.

2012-4 The Moosehorn Road job will require the replacement of four pole mounted transformers to conform to the new 14.4kV line.	$19,272
2012-2 The new housing development in Sioux Lookout will require the installation of five new pole mounted transformers.	$17,116
2012-2 The newly constructed 4 plex unit will require a single pole mount transformer to be installed.	$4,279
2012-3 General overhead upgrades will require the installation of a single pole mount transformer and three single phase pad mount transformers in 2012.	$29,804
Sub Total	**$70,471**
Contributed Capital*	**$17,618**
SLHI Total Budget	**$88,089**

*The amount shown as Contributed Capital is based on historical values calculated through Economic Evaluation Model studies.

9.1.4 Distribution Meters (Act#1860)

2012-2 New housing will require the installation of nine meters in 2012.	$1,512
2012-2 Four meters will be required by the 4 plex unit when completed.	$672
2012-3 During the course of general upgrades in 2012 three new distribution meters will be needed.	$504
2012-2 The construction of new offices in Sioux Lookout will require the addition of four new distribution meters to the system.	$672
SLHI Total Budget	**$3,360**

9.1.5 Equipment Purchases

2012-7 Line Truck H-3	$150,000
2012-6 Tools	$10,000
2012-8 Security System	$5,500
2012-9 Office Equipment	$5,000
2012-5 Computer Hardware and Software for office	$1,500
SLHI Total Budget	**$172,000**

9.2 Capital Expense 2013 - Details

9.2.1 Distribution Lines Overhead (Act #1830 & 1835)

This account includes Poles, Towers, Fixtures, Conductors and Devices.

2013-1 Pole replacements in 2013 are currently planned to include 20 new poles replacing those in questionable condition throughout the system.	$46,923
2013-3 General upgrades are planned for 2013 which will include 300m of single phase primary circuit and 900m of secondary circuit.	$7,490
2013-2 Providing power to new houses will require the installation of three new poles, 100m of primary conductor and 500m of secondary conductor.	$6,928
Total Budget	**$61,341**

9.2.2 Distribution Lines Underground (Act #1840 & 1845)

As in 2012 this account becomes harder to forecast as we go further into the future. The following was made with the best data available at the time.

2013-2 New housing in 2013 will require the installation of 600 meters of primary cable and 600 meters of secondary cable.	$20,216
2013-3 30m of Primary cable and 90m of secondary cable will be installed as part of general upgrades in 2013.	$1,735
Sub Total	**$21,951**
Contributed Capital*	**$5,488**
SLHI Total Budget	**$27,439**

*The amount shown as Contributed Capital is based on historical values calculated through Economic Evaluation Model studies.

9.2.3 Submarine Cable (Act#1840 & 1845)

2013-4 The replacement of the sturgeon river submarine cable used to feed South Shore Drive will require 2000m of submarine cable.	$72,200
SLHI Total Budget	**$72,200**

9.2.4 Distribution Transformers (Act #1850)

This account is similar to the underground distribution account, as its dependent on the activities of Developers. Again our best guess at the time is shown below.

2013-3 General upgrades during 2013 will require five pole mounted and one new pad mounted transformer.	$30,154
2013-2 New housing construction will provide a requirement for an addition of five overhead and one underground transformers in the system.	$29,613
Sub Total	**$59,767**
Contributed Capital*	**$14,942**
SLHI Total Budget	**$74,709**

*The amount shown as Contributed Capital is based on historical values calculated through Economic Evaluation Model studies.

9.2.5 Distribution Meters (Act#1860)

2013-2 There are 10 new meters planned for installation in 2013. All will be for newly constructed houses.	$1,680
SLHI Total Budget	**$1,680**

9.2.6 Equipment Purchases

2013-5 Backhoe	$86,000
2013-6 Amcorder Recording Ammeter	$7,000
2013-9 Tools	$5,500
2012-9 Office Equipment	$5,000
2012-5 Computer Hardware and Software for office	$1,500
SLHI Total Budget	**$105,000**

10.0 Information Systems

SLHI has identified the need for better information systems to address the current and future requirements, related to preparation of asset management plans, assessment of distributed generation project impacts on the existing system and development of a smart grid strategy in response to the Green Energy Act. It is anticipated, that additional drivers are likely to present themselves in the future to further support the need for these systems. The need for these systems is described in more detail below.

10.1 Analysis

SLHI currently uses contract services to assess system losses and to calculate system protection coordination studies. This process will be further enhanced and supported by the implementation of an asset management system and/or a GIS.

System studies include protection coordination, system loss calculation, conductor sizing, voltage drop and system loading. Additional analysis could include system optimization, load balancing and arc flash protection. The analyses are conducted to address the safe and reliable operation of the distribution system.

It is important to SLHI to have the ability to analyze system changes and impacts due to customer demands, on a timely basis. This is even more important when considering the requirements related to the DAT and CIA, needed to respond on a timely basis to customer driven FIT and micro-FIT projects.

10.2 Asset Management System (GIS) Implementation

The utility asset information should be maintained in a central repository, representing a single source of truth for the organization. This information should further be integrated across all functions, thus linking engineering, operational, customer and financial information for all assets. This could be further enhanced by a network connectivity model, which more accurately represents the impact of assets on one another. All SLHI GIS and Asset data is currently hosted by Automated Solutions International Inc. in Cambridge Ontario.

The asset management model proposed by SLHI for implementation would allow linking of the soon to be available smart meter data with a system model, thus providing a better foundation for the calculation of SLHI asset data health indices as well as provide the foundation for the potential calculation of feeder health indices.

As mentioned, the model would also be a foundation for system analysis studies, which will be essential for addressing FIT and microFIT applications and assessing their potential impacts on the SLHI distribution system.

10.3 Improved Financial Reporting

The potential implementation of the IFRS reporting system will impact current processes, in particular as they apply to the installation, maintenance and disposal costs of major assets, such as poles, transformers and station equipment. It is expected that the asset management system to be implemented will support this requirement.

10.4 System Operation and Monitoring

The SLHI distribution system is a combination of rural and urban, spread out over a large service area. The response to trouble calls and outages is generally within industry norms, with 2011 being an exception caused by unusual levels of storm disruption. Section 2.2.2 provides the statistics which indicate these facts. The need for remote control of switching equipment at this time is minimal. However, as systems become more complex due to distributed generation requirements, system control and operation will also become more complex and the supporting systems may need to be sophisticated enough to support these operational needs.

SLHI will implement a flexible and expandable system, based initially on system monitoring, with the ability to evolve and support remote operation functions. The system monitoring will support and collaborate with the smart meter data to provide SLHI with better system level information and allow more accurate system analysis studies.

11.0 Summary

In summary, much of the SLHI system was reconstructed during the 1980s and 1990's and is still in good condition with only minor upgrades required. During this reconstruction the system was upgraded from 4.16kV to 14.4kV. This increased voltage level has improved the distribution of power throughout the large geographical area covered by SLHI by reducing losses.

Some pockets of 7.2kV still exist on single phase branches of the system. Where economical, these pockets will be replaced or converted over time to 14.4kV. SLHI is not actively eliminating 7.2kV system, nor will SLHI be investing in any new equipment for the 7.2kV system.

Data collection efforts over the last few years have provided SLHI with an increased amount of information on many of its assets. This information, correlated by an online database is being used to plan improvements and upgrades to the system.

The following observations can be made:

- Inspection results are being recorded electronically, to allow correlation with asset characteristics
- Correlate outage and system performance information with asset condition and maintenance information to provide a better foundation for 5 year capital and maintenance budget plans
- SLHI will have the ability to review current maintenance standards, based on more complete asset data combined with inspection and asset condition information, and adjust current maintenance standards for each asset type.
- A mixture of system upgrades and new development are driving construction in SLHI. With better correlation of information from the town on new development the planning process can be improved.

(Developed through the OEB's Appendix C – Minimum Inspection Requirements)

Inspection Cycles for Overhead and Underground

Sioux Lookout Hydro Inc(SLHI) ensures that only persons qualified under the Occupation of Health and Safety Act are involved in inspection activities. Since some inspections can expose inspectors to energized lines or high voltage circuits and equipment, and may include inspection and repair, a qualified person is assigned to this work. This assumes that they are both properly trained to protect both themselves and the public, and to respond to those emergencies, which may arise during inspections.

The patrol inspection is defined as follows:

> Patrol or simple visual inspections consisting of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, and individual pieces of equipment carefully observed ant their condition noted and recorded. The specifics of these inspections would be recorded, and a summary document prepared in the distributor's annual reports as part of their rates or licensing submissions.

In all cases, SLHI ensures that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

SLHI will file both annual summary reports of detailed patrol inspection activities that have taken place during the previous year as well as an outline of inspect tion plans ("compliance plans") for the forthcoming year.

Inspection cycles are categorized by SLHI's major distribution facilities:

Distribution Transformers
Switching and Protective Devices
Regulators
Capacitors
Conductors and Cables
Vegetation
Poles/Supports
Civil Infrastructure

For each of these facilities SLHI will further distinguish between overhead facilities and underground facilities. SLHI will also separate according to the facilities' location and the relative population density in the locale.

- Rural means those areas that are less populous suburban areas and are outside of a standard metropolitan area. Generally, rural will be defined on a circuit or sub-circuit basis by each utility, as areas with a line density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the utility might want to treat something as urban thought it would otherwise be defined as "rural" according to this definition.
- Urban, means areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

Line Patrol Inspection Checklist:

Transformers and switching kiosks:
- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place
- Grading changes
- Access changes (Shrubs, trees, etc.)
- Phase indicators and unit numbers match operating map(where used)
- Leaking oil
- Flashed or cracked insulators
- Pad mounted – lid damage, missing bolts, cabinet damage, public security lock damage

Switching/Protective Devices
- Overhead
  - Bent, broken bushings and cutouts,
  - Damaged lightning arresters, control boxes, current and potential transformers
- Underground
  - Security and structural condition of enclosure
- Pad mounted
  - Security and structural condition of enclosure
- Regulators
  - Condition of bushings
  - Tank corrosion/leaks
  - Damaged disconnect switches or lightning arresters
- Capacitors
  - Conditions of bushings
  - Tank corrosion/leaks
  - Damaged cutouts, disconnects or control cabinet
- Conductors and Cables
  - Low conductor clearance
  - Broken/frayed conductors or tie wires
  - Tree Conditions, exposed broken ground conductors
  - Broken strands, bird caging, and excessive or inadequate sag

- Insulation fraying on secondary especially open wire

Pole/Supports
- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Wood pecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Hardware and attachments
- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated (difficult to see)
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Equipment Installations (includes transformers)
- Contamination/discoloration of bushings
- Oil Leaks
- Rust
- Ground lead attachments
- Ground wires on arrestors unattached
- Bird or animal nests
- Vines or brush growth interference
- Evidence of bushing flashover
- Accessibility compromised
- Vegetation and Right of Way
- Leaning or broken "danger" trees
- Growth into line of "climbing" trees
- Unapproved/unsafe occupation or secondary use

Civil Infrastructure – For example, buildings that house the equipment may need attention (cracking, fire hazard, etc.). In addition, cable chambers, underground vaults and tunnels crossing the rail track or water are also included in this category. These inspections will be conducted in the patrol of the equipment with which they are "associated".

Underground Systems:

With respect to underground systems, riser poles will be checked as with an overhead patrol, with a visual check of cable, cable guards, terminators and arrestors. While it is not possible to inspect underground cable directly, the system will be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface.

Since cable is difficult to check, the system will be checked for exposed cable and/or grading changes that may have brought cable or wire too close to the surface.

Table C-1 below outlines SLHI's inspection cycles in years. Table C-2 is the inspection report to be completed on an annual basis. Finally Table C-3 is a sample of the patrol deficiency record to be used to document areas of concern.

TABLE C-1 Electric Utility System Inspection Cycles (Maximum Intervals in Years)

Major or Substantial Distribution Facility*	**Patrol**			**Patrol**		
Distribution Transformers	**Urban**			**Rural**		
Overhead	3			3		
Submersible	3			3		
Vault	3			3		
Pad Mounted	3			3		
Stations (see note below)	**Outdoor Open**	**Outdoor Enclosed**	**Indoor Enclosed**	**Outdoor Open**	**Outdoor Enclosed**	**Indoor Enclosed**
Transformer Station	n/a	n/a	n/a	n/a	n/a	n/a
Distribution Station	n/a	n/a	n/a	n/a	n/a	n/a
Customer Specific Substation	n/a	n/a	n/a	n/a	n/a	n/a
Lines and Associated Equipment						
Regulators	3			3		
Switching and Protective Devices	3			3		
Capacitors	3			3		
Conductors and Cables						
Overhead	3			3		
Underground	3			3		
Submarine	3			3		
Vegetation	3			3		
Poles	3			3		
Civil Infrastructure	3			3		

TABLE C-2 Sample Annual Inspection Summary Report

Distributor		
Reviewed by	**Name:**	**Position/Title:**
Date:	**Signature:**	

DESCRIPTION Part 1 - Lines		**Percentage of Distribution System Scheduled for Patrol (%)**	**Percentage of Distribution System Actually Patrolled (%)**	**Reason Patrol was not Completed**	**Date Patrol will be Completed**
Overhead Plant Transformers Switching & Protective Devices Regulators Capacitors Conductor Vegetation Poles Civil Infrastructure	**Urban**				
	Rural				
Underground Plant Transformers Switching & Protective Devices Regulators Capacitors Cable Civil Infrastructure	**Urban**				
	Rural				

TABLE C-3 Sample Patrol Deficiency Record

Area/District ________________ Date __________________________ Circuit ________________________ Patrolled by _______________________ Grid ________________________ Page ______ of _____

Location	Equipment Id. No.	Equipment Classification	Repair Required/ Problem	Corrective Action Priority		Assigned to or Work Order No.	Date Repair Completed or Scheduled
				Grade 1	Grade 2		
Number of Deficiencies for the Circuit/Area							

SIOUX LOOKOUT HYDRO INC.
HAZARD IDENTIFICATION

TRANSFORMER #: ____________________

911 LOCATION: ____

HAZARD DESCRIPTION: ____

REPAIRS TO BE COMPLETED BY: ____

HIGH PRIORITY □

LOW PRIORITY □

OUTAGE REQUIRED □

MATERIALS REQUIRED:

COMMENTS:

SIGN: ______________________________ DATE: ____________________

FORWARD COPY TO FOREMAN

SIOUX LOOKOUT HYDRO INC.
LINE PATROL INSPECTION CHECKLIST
OVERHEAD AND PADMOUNT TRANSFORMERS

DATE:
LOCATION: ______________________
FEEDER:
OPERATION MAP#:
TRANSFORMER #:
□ Overhead
□ Underground

CONDITION DESCRIPTION	**GOOD**	**FAIR**	**BAD**
PAINT CONDITION			
CORROSION			
PLACEMENT ON PAD			
PENTA BOLT IN PLACE			
LOCK IN PLACE AND IN WORKING CONDITION			
GRADING CHANGES, WASHOUTS			
ACCESS TO CHANGE			
ACCESS TO SWITCHING			
CONDITION OF SECONDARY CABLES/HEAT, LOOSE			
CONDITION OF PRIMARY ELBOW AND CABLE			
PRIMARY CABLE NUMBERS			
SECONDARY CABEL NUMBERS			
LEAKING OIL			
VEGETATION OR TREES			
PAD CONDITION/CABINET DAMAGED			
GROUND WIRE BROKEN OR DISCONNECTED			
STAPLES MISSING ON GROUND WIRE			
MOULDING MISSING ON GROUND WIRE			
CRACKED INSULATORS ON PRIMARY OR SECONDARY BUSSING			
CUT OUT CONDITION LOOSE			
ARRESTOR - POLYMOR			
ARRESTOR - PORCELAIN			
15 KV CHANCE CUTOUT □ Yes □ No			

APPENDIX 2-B

Green Energy Plan

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

September 10, 2012

Regulatory Affairs
Ontario Power Authority
120 Adelaide St. W. Suite 1600
Toronto, On M5H 1T1
Email: RegulatoryAffairs@powerauthority.on.ca

RE: Sioux Lookout Hydro Inc. – Basic Green Energy Act Plan

To Whom It May Concern:

Sioux Lookout Hydro is pleased to provide you with its Basic Green Energy Act Plan in accordance with Board Decision 2009-0397, for your consideration and comments.

The Plan addresses the following points as noted in the OEB requirements for a basic plan:

1. Description of the distribution system and current capacity to accommodate generation from renewable energy generation facilities.
2. Factors that may limit the ability to connect renewable generation facilities
3. Identification of any expenditures related to renewable generation connections over 10 KW, for which Sioux Lookout Hydro has no expenditures planned.
4. Description of any relevant or unique challenges and opportunities associated with the distributor's system.

If there are any questions or concerns regarding the Plan, 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

Encl/

GREEN ENERGY ACT PLAN

SEPTEMBER 2012

SIOUX LOOKOUT HYDRO INCORPORATED
25 FIFTH AVENUE, P.O. BOX 908
SIOUX LOOKOUT, ON P8T 1B3

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INTRODUCTION

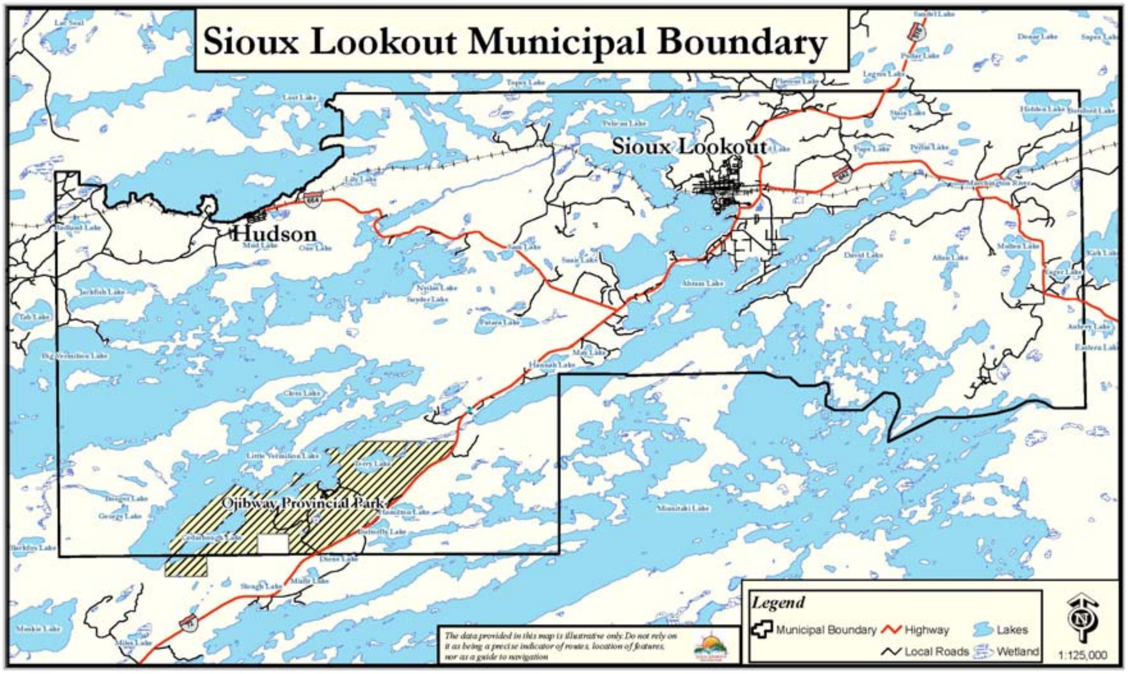
Sioux Lookout Hydro Inc. (SLHI) is a licensed electricity distributor for the Municipality of Sioux Lookout servicing approximately 2,750 customers. As a condition of license and in accordance with the Ontario Energy Board’s (OEB) filing requirements of EB-2009-0397, Distribution System Plans – Filing under Deemed Conditions of License, SLHI has prepared a basic Green Energy Act Plan (GEA Plan) for its franchise area for the 2013 to 2017 period.

The GEA Plan is intended to provide information to the OEB and interested stakeholders regarding the preparedness of SLHI’s distribution system to accommodate the connection of renewable generation and the expansion or reinforcement necessary to accommodate renewable generation and the development of the smart grid.

Sioux Lookout is located in northwestern Ontario as shown in Figure 1. Below. The service territory for SLHI is the municipal boundaries of the town and is shown in figure 2.

Figure 1

Figure 2



In preparing this document SLHI consulted with Hydro One Networks Inc. (HONI) & the Ontario Power Authority.

OVERVIEW OF SIOUX LOOKOUT HYDRO'S DISTRIBUTION SYSTEM

SLHI operated a 25 kV distribution system connected to the Sam Lake DS. The Sam Lake DS is owned and operated by Hydro One Networks Inc.

Description of Sioux Lookout Hydro's Feeders

The Sam Lake DS provides four feeders to the SLHI system. Their usage is explained below:

F1: This feeder stretches West from the station to the town of Hudson. This community represents most of the load on this feeder. Some additional load exists between the community and station where small pockets of residences are found. This feeder also supplies a Hydro One load transfer to Frenchman's Head, a small community across the lake from Hudson. Submarine cable is used for this load Transfer.

F2: This feeder extends South East of the station to provide power for the South half of Sioux Lookout including the South Shore of Sturgeon River. The blue phase of this feeder branches South into rural areas on Highway 72.

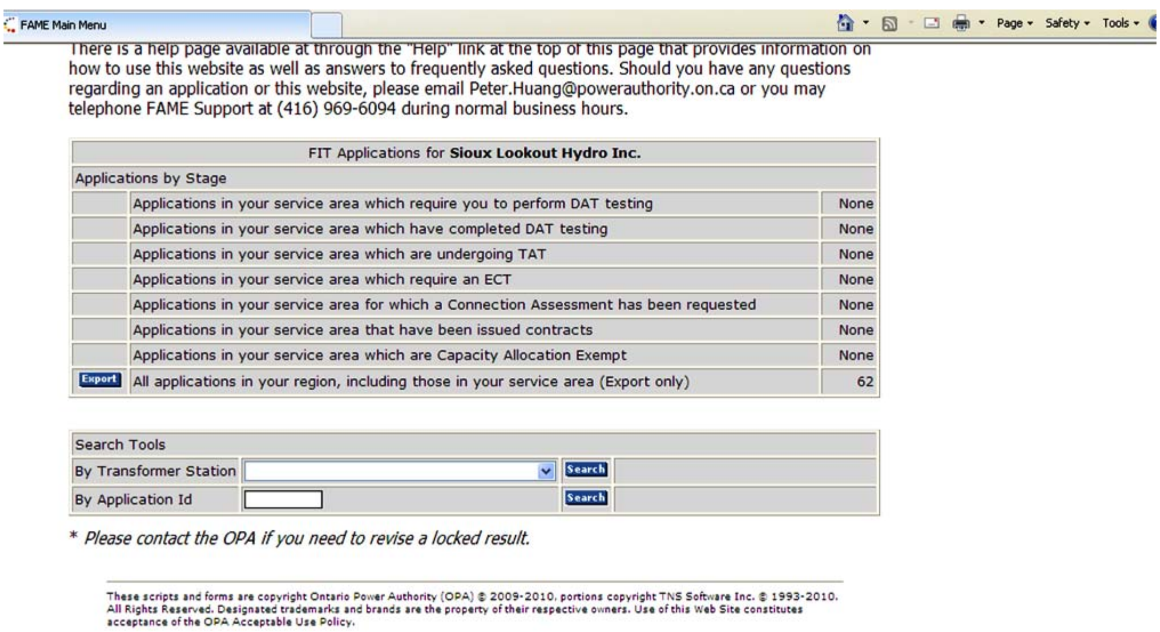
F3: This feeder travels East of the station to the community of Sioux lookout where it feeds the upper half of the community. This stretch includes some of the heavier loads in the town including the airport and hospital. This blue phase of this feeder continues East of the town to provide a rural area on Highway 642 and load transfer for Hydro One.

F4: This feeder does not currently carry any load. Previously it had been a dedicated feeder for the Hudson Saw Mill. With the mill's closure the load has been removed.

APPLICATIONS FROM RENEWABLE GENERATORS OVER 10 KW

SLHI does not have any applications from renewable generators over 10 kW for connection, and the OPA has not received any applications for renewable generators over 10 kW for the FIT Program for SLHI's service territory. See Figure 3 below taken from the OPA Fame website September 10, 2012.

Figure 3



FAME Main Menu

There is a help page available at through the "Help" link at the top of this page that provides information on how to use this website as well as answers to frequently asked questions. Should you have any questions regarding an application or this website, please email Peter.Huang@powerauthority.on.ca or you may telephone FAME Support at (416) 969-6094 during normal business hours.

FIT Applications for **Sioux Lookout Hydro Inc.**		
Applications by Stage		
	Applications in your service area which require you to perform DAT testing	None
	Applications in your service area which have completed DAT testing	None
	Applications in your service area which are undergoing TAT	None
	Applications in your service area which require an ECT	None
	Applications in your service area for which a Connection Assessment has been requested	None
	Applications in your service area that have been issued contracts	None
	Applications in your service area which are Capacity Allocation Exempt	None
Export	All applications in your region, including those in your service area (Export only)	62

Search Tools		
By Transformer Station		Search
By Application Id		Search

* *Please contact the OPA if you need to revise a locked result.*

OVERALL POTENTIAL FOR DEVELOPING RENEWABLE GENERATION

Currently SLHI has 6 solar MicroFit projects connected, consisting of one (1) ground mount and five (5) rooftop mounted, for a total capacity of 59.41 kW. There are two (2) applications in pending connection status as well as one (1) in submitted status.

PLANNED DEVELOPMENT AND CONSTRAINTS WITHIN THE DISTRIBUTOR'S SYSTEM RELATED TO THE CONNECTION OF RENEWABLE GENERATION

The Sam Lake DS currently has 16MW of station availability to accommodate additional renewable generation. As an embedded distributor to Hydro One, SLHI will have to communicate and receive authorization from Hydro One before undertaking any FIT projects.

The following information was received from the OPA regarding SLHI's ability to connect FIT projects:

"For Sam Lake DS, this station has 16 MW of station availability to accommodate additional renewable generation. Please note this availability is based only on the station's ability to connect. For a project to be issued a FIT contract, the project must be accommodated at all levels, including distribution system, station, local transmission circuits, and area transmission. As you notice the TAT Table also list a Northwest area availability of 0 MW. This means the Northwest is fully subscribed and no FIT project will be offered a contract due to limitations on the bulk transmission system (the East-West Tie).

Currently the OPA is actively participating in the OEB's Transmission Designation Process to designate a transmitter to develop the East-West Tie expansion. The project has a planned in-service date of 2017. You can find further information on OEB's web site. There is also an on-going effort for transmission system expansion to accommodate additional load increases in the area North of Dryden."

See Table 1 below for an excerpt of the OPA's Transmission Availability Table for small FIT 2012:

Table 1

		Capability for Small FIT 2012					
Station Name	Bus Name	Thermal Capacity (MW) (See note 1)	Short Circuit Capacity (MVA) (See note 1)	Limited by Known Upstream Transmission	Area	Area Availability (MW)	Station Owner
SAM LAKE DS	Total	16	92		Northwest	0	HYDRO ONE NETWORKS INC.

Note 1: Capability values indicated reflect the reservation of 2 MW of capacity for microFIT projects at each station (2 MW per bus at stations with more than one bus).

The full Transmission Availability Table can be found using the link below:

http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

CONCLUSION

Sioux Lookout Hydro will continue to monitor the capacity for the Northwest Region. Given the OPA's information regarding the Northwest's limitations, SLHI will not be applying for rates to support investments for FIT installations for at least another 5 years. However, SLHI will continue to assist and work with MicroFit applicants to ensure timely connections.

APPENDIX 2-C

OPA Letter of Comment

OPA Letter of Comment:

Sioux Lookout Hydro Inc.

Basic Green Energy Act Plan

September 20, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, the Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Sioux Lookout Hydro Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Sioux Lookout Hydro Inc. ("SLHI") dated September 10, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

On page 3 of the Plan, SLHI indicates that currently it has 6 connected solar microFIT projects consisting of 1 ground mount and 5 rooftop mounted projects for a total capacity of 59.41 kW. The Plan also indicates that SLHI has 2 applications in pending connection status and 1 in submitted status. SLHI's Plan also indicates it has no applications from renewable generators over 10 kW for connection.

According to OPA's information, as of September 14, 2012, there are 6 connected microFIT projects totalling approximately 50 kW of capacity in SLHI's distribution system. There are also 3 microFIT projects with a total capacity of approximately 25 kW that have applied to connect to SLHI's service territory. There are no applications or contracts for renewable generators over 10 kW in SLHI's service territory.

Upstream Transmission Constraints

As noted in the Transmission Availability Table published by the OPA on April 5, 2012, the Northwest area is fully subscribed and has no capability to accommodate additional renewable generation. All renewable generation resources connecting to SLHI's system fall within the Northwest area. The area constraint is expected to limit the future uptake of large and small FIT renewable resources in SLHI's service territory. The East-West Tie expansion project, one of the 5 priority transmission projects in the government's Long-Term Energy Plan, is a major component in providing relief to the Northwest; however the project is not expected to be in service prior to 2017.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

The updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows: http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that SLHI's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Sioux Lookout Hydro Inc.'s Basic GEA Plan.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

APPENDIX 2-D

Service Quality & Reliability Performance

2008 – 2011

CONNECTION OF NEW SERVICES - LOW VOLTAGE (LV) (2008-2011)

OEB Approved Standard: at least 90% on a yearly basis

2011	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
Jan	0	0	0.00%
Feb	1	1	100.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	4	4	100.00%
Jun	10	10	100.00%
Jul	6	6	100.00%
Aug	1	1	100.00%
Sep	1	1	100.00%
Oct	2	2	100.00%
Nov	5	5	100.00%
Dec	1	1	100.00%
Annual Total	31	31	100.00%

2010	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
Jan	1	1	100.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	2	2	100.00%
May	0	0	0.00%
Jun	2	2	100.00%
Jul	4	4	100.00%
Aug	3	3	100.00%
Sep	6	6	100.00%
Oct	1	1	100.00%
Nov	7	7	100.00%
Dec	1	1	100.00%
Annual Total	27	27	100.00%

2009	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	1	1	100.00%
Apr	2	2	100.00%
May	1	1	100.00%
Jun	0	0	0.00%
Jul	3	3	100.00%
Aug	6	6	100.00%
Sep	2	2	100.00%
Oct	9	9	100.00%
Nov	2	2	100.00%
Dec	1	1	100.00%
Annual Total	27	27	100.00%

2008	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	1	1	100.00%
Apr	0	0	0.00%
May	1	1	100.00%
Jun	0	0	0.00%
Jul	4	4	100.00%
Aug	4	4	100.00%
Sep	5	5	100.00%
Oct	6	6	100.00%
Nov	8	8	100.00%
Dec	0	0	0.00%
Annual Total	29	29	100.00%

CONNECTION OF NEW SERVICES - HIGH VOLTAGE (HV) (2008-2011)

OEB Approved Standard: at least 90% on a yearly basis

2011	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	0	0	0.00%

2010	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	0	0	0.00%

2009	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	0	0	0.00%

2008	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	0	0	0.00%

APPOINTMENT SCHEDULING (2008-2011)

OEB Approved Standard: at least 90% on a yearly basis

2011	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
Jan	4	4	100.00%
Feb	1	1	100.00%
Mar	2	2	100.00%
Apr	5	5	100.00%
May	5	5	100.00%
Jun	11	11	100.00%
Jul	5	5	100.00%
Aug	12	12	100.00%
Sep	18	19	94.74%
Oct	7	7	100.00%
Nov	3	4	75.00%
Dec	3	4	75.00%
Annual Total	76	79	96.20%

2010	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
Jan	1	1	100.00%
Feb	1	1	100.00%
Mar	3	3	100.00%
Apr	5	5	100.00%
May	9	9	100.00%
Jun	14	14	100.00%
Jul	9	9	100.00%
Aug	14	14	100.00%
Sep	13	14	92.86%
Oct	17	17	100.00%
Nov	12	12	100.00%
Dec	3	3	100.00%
Annual Total	101	102	99.02%

2009	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
Jan	0	0	0.00%
Feb	4	4	100.00%
Mar	0	0	0.00%
Apr	8	8	100.00%
May	11	11	100.00%
Jun	10	10	100.00%
Jul	9	9	100.00%
Aug	17	17	100.00%
Sep	7	7	100.00%
Oct	12	12	100.00%
Nov	3	3	100.00%
Dec	2	2	100.00%
Annual Total	83	83	100.00%

UNDERGROUND CABLE LOCATES (2008)

OEB Approved Standard: 90% or more

2008	# of Underground Cable Locates completed within 5 days	# of UCL Requested	% of Underground Cable Locates completed within 5 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	7	7	100.00%
May	8	8	100.00%
Jun	9	9	100.00%
Jul	9	9	100.00%
Aug	7	7	100.00%
Sep	9	9	100.00%
Oct	2	2	100.00%
Nov	4	4	100.00%
Dec	1	1	100.00%
Annual Total	56	56	100.00%

APPOINTMENTS MET (2008-2011)

OEB Approved Standard: at least 90% on a yearly basis

2011

	# of appointements completed as required	# of appointments scheduled with customer/representative	% appointments met
Jan	4	4	100.00%
Feb	2	2	100.00%
Mar	2	2	100.00%
Apr	5	5	100.00%
May	9	9	100.00%
Jun	21	21	100.00%
Jul	11	11	100.00%
Aug	13	13	100.00%
Sep	19	20	95.00%
Oct	9	9	100.00%
Nov	8	9	88.89%
Dec	4	5	80.00%
Annual Total	107	110	97.27%

2010

	# of appointements completed as required	# of appointments scheduled with customer/representative	% appointments met
Jan	1	1	100.00%
Feb	1	1	100.00%
Mar	2	2	100.00%
Apr	4	4	100.00%
May	5	5	100.00%
Jun	11	11	100.00%
Jul	7	7	100.00%
Aug	13	13	100.00%
Sep	12	12	100.00%
Oct	13	14	92.86%
Nov	10	10	100.00%
Dec	3	3	100.00%
Annual Total	82	83	98.80%

2009

	# of appointements completed as required	# of appointments scheduled with customer/representative	% appointments met
Jan	0	0	0.00%
Feb	4	4	100.00%
Mar	0	0	0.00%
Apr	8	8	100.00%
May	11	11	100.00%
Jun	10	10	100.00%
Jul	9	9	100.00%
Aug	17	17	100.00%
Sep	7	7	100.00%
Oct	12	12	100.00%
Nov	3	3	100.00%
Dec	2	2	100.00%
Annual Total	83	83	100.00%

2008

	# of visits to customer's site where Appointment date and time met	# of Appointments requiring visit to customer's site	% appointments met
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	8	8	100.00%
May	10	10	100.00%
Jun	9	9	100.00%
Jul	9	9	100.00%
Aug	6	6	100.00%
Sep	9	9	100.00%
Oct	2	2	100.00%
Nov	4	4	100.00%
Dec	1	1	100.00%
Annual Total	58	58	100.00%

RESCHEDULING A MISSED APPOINTMENT (2008-2011)

OEB Approved Standard: 100% on a yearly basis

2011	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	1	1	100.00%
Oct	0	0	0.00%
Nov	1	1	100.00%
Dec	1	1	100.00%
Annual Total	3	3	100.00%

2010	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	1	1	100.00%
Sep	0	0	0.00%
Oct	2	2	100.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	3	3	100.00%

2009	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	0	0	0.00%

TELEPHONE ACCESSIBILITY (2008-2011)

OEB Approved Standard: at least 65% on a yearly basis

2011	# of qualified incoming calls answered within 30 Seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
Jan	523	543	96.32%
Feb	474	491	96.54%
Mar	547	568	96.30%
Apr	611	619	98.71%
May	724	736	98.37%
Jun	642	658	97.57%
Jul	421	440	95.68%
Aug	488	500	97.60%
Sep	617	641	96.26%
Oct	543	550	98.73%
Nov	468	491	95.32%
Dec	419	436	96.10%
Annual Total	6477	6673	97.06%

2010	# of qualified incoming calls answered within 30 Seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
Jan	677	701	96.58%
Feb	484	493	98.17%
Mar	635	642	98.91%
Apr	889	902	98.56%
May	752	768	97.92%
Jun	716	735	97.41%
Jul	723	739	97.83%
Aug	563	572	98.43%
Sep	702	722	97.23%
Oct	543	566	95.94%
Nov	628	645	97.36%
Dec	480	495	96.97%
Annual Total	7792	7980	97.64%

2009	# of qualified incoming calls answered within 30 Seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
Jan	585	587	99.66%
Feb	580	583	99.49%
Mar	532	538	98.88%
Apr	617	628	98.25%
May	714	723	98.76%
Jun	736	746	98.66%
Jul	652	666	97.90%
Aug	651	669	97.31%
Sep	641	657	97.56%
Oct	587	611	96.07%
Nov	485	501	96.81%
Dec	526	555	94.77%
Annual Total	7306	7464	97.88%

2008	# of general inquiry telephone calls answered within 30 Seconds	# of general Inquiry calls	% qualified incoming calls answered within 30 seconds
Jan	406	406	100.00%
Feb	327	327	100.00%
Mar	323	323	100.00%
Apr	413	413	100.00%
May	410	410	100.00%
Jun	826	826	100.00%
Jul	346	346	100.00%
Aug	308	308	100.00%
Sep	296	296	100.00%
Oct	392	392	100.00%
Nov	300	300	100.00%
Dec	271	271	100.00%
Annual Total	4618	4618	100.00%

TELEPHONE CALL ABANDON RATE (2008-2011)

OEB Approved Standard: 10% or less on a yearly basis

2011	**# of qualified incoming calls abandoned after 30 seconds**	**# of qualified incoming calls**	**% qualified incoming calls abandoned after 30 seconds**
Jan	11	543	2.03%
Feb	5	491	1.02%
Mar	12	568	2.11%
Apr	4	619	0.65%
May	1	736	0.14%
Jun	10	658	1.52%
Jul	9	440	2.05%
Aug	1	500	0.20%
Sep	3	641	0.47%
Oct	1	550	0.18%
Nov	12	491	2.44%
Dec	9	436	2.06%
Annual Total	78	6673	1.17%

2010	**# of qualified incoming calls abandoned after 30 seconds**	**# of qualified incoming calls**	**% qualified incoming calls abandoned after 30 seconds**
Jan	5	701	0.71%
Feb	1	493	0.20%
Mar	0	642	0.00%
Apr	1	902	0.11%
May	6	768	0.78%
Jun	9	735	1.22%
Jul	4	739	0.54%
Aug	2	572	0.35%
Sep	4	722	0.55%
Oct	9	566	1.59%
Nov	5	645	0.78%
Dec	9	495	1.82%
Annual Total	55	7980	0.69%

2009	**# of qualified incoming calls abandoned after 30 seconds**	**# of qualified incoming calls**	**% qualified incoming calls abandoned after 30 seconds**
Jan	2	587	0.34%
Feb	3	583	0.51%
Mar	6	538	1.12%
Apr	11	628	1.75%
May	9	723	1.24%
Jun	10	746	1.34%
Jul	14	666	2.10%
Aug	18	669	2.69%
Sep	16	657	2.44%
Oct	24	611	3.93%
Nov	16	501	3.19%
Dec	29	555	5.23%
Annual Total	158	7464	2.12%

WRITTEN RESPONSES TO ENQUIRIES (2008-2011)

OEB Approved Standard: at least 80% on a yearly basis

2011	# of written responses provided within 10 days	# of qualified enquiries received	% written repsonses provided within 10 days
Jan	1	1	100.00%
Feb	3	3	100.00%
Mar	2	2	100.00%
Apr	1	1	100.00%
May	2	2	100.00%
Jun	2	2	100.00%
Jul	2	2	100.00%
Aug	2	2	100.00%
Sep	1	1	100.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	16	16	100.00%

2010	# of written responses provided within 10 days	# of qualified enquiries received	% written repsonses provided within 10 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	1	1	100.00%
May	0	0	0.00%
Jun	4	4	100.00%
Jul	0	0	0.00%
Aug	2	2	100.00%
Sep	1	1	100.00%
Oct	0	0	0.00%
Nov	1	1	100.00%
Dec	2	2	100.00%
Annual Total	11	11	100.00%

2009	# of written responses provided within 10 days	# of qualified enquiries received	% written repsonses provided within 10 days
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	2	2	100.00%
Apr	2	2	100.00%
May	0	0	0.00%
Jun	1	1	100.00%
Jul	1	1	100.00%
Aug	0	0	0.00%
Sep	1	1	100.00%
Oct	0	0	0.00%
Nov	1	1	100.00%
Dec	2	2	100.00%
Annual Total	10	10	100.00%

2008	# of Requests for WRI provided within 10 work days	# of Requests for WRI	% of Requests for WRI provided within 10 working days
Jan	1	1	100.00%
Feb	0	0	0.00%
Mar	1	1	100.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	1	1	100.00%
Dec	0	0	0.00%
Annual Total	3	3	100.00%

EMERGENCY RESPONSE URBAN (2008-2011)

OEB Approved Standard: at least 80% on a yearly basis

2011	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	1	1	100.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	1	1	100.00%

2010	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	1	1	100.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	1	1	100.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	2	2	100.00%

2009	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
Jan	3	3	100.00%
Feb	4	4	100.00%
Mar	2	2	100.00%
Apr	1	1	100.00%
May	0	0	0.00%
Jun	5	5	100.00%
Jul	7	7	100.00%
Aug	3	3	100.00%
Sep	1	1	100.00%
Oct	0	0	0.00%
Nov	3	3	100.00%
Dec	0	0	0.00%
Annual Total	29	29	100.00%

2008	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
Jan	1	1	100.00%
Feb	0	0	0.00%
Mar	1	1	100.00%
Apr	2	2	100.00%
May	3	3	100.00%
Jun	9	9	100.00%
Jul	9	10	90.00%
Aug	5	5	100.00%
Sep	1	1	100.00%
Oct	1	1	100.00%
Nov	1	1	100.00%
Dec	0	0	0.00%
Annual Total	33	34	97.06%

EMERGENCY RESPONSE RURAL (2008-2011)

OEB Approved Standard: at least 80% on a yearly basis

2011	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	0	0	0.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	1	1	100.00%
Dec	0	0	0.00%
Annual Total	1	1	100.00%

2010	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
Jan	0	0	0.00%
Feb	1	1	100.00%
Mar	0	0	0.00%
Apr	0	0	0.00%
May	0	0	0.00%
Jun	0	0	0.00%
Jul	1	1	100.00%
Aug	0	0	0.00%
Sep	0	0	0.00%
Oct	0	0	0.00%
Nov	0	0	0.00%
Dec	0	0	0.00%
Annual Total	2	2	100.00%

2009	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	5	5	100.00%
Apr	1	1	100.00%
May	13	13	100.00%
Jun	6	6	100.00%
Jul	6	6	100.00%
Aug	2	2	100.00%
Sep	1	1	100.00%
Oct	2	2	100.00%
Nov	0	0	0.00%
Dec	1	1	100.00%
Annual Total	37	37	100.00%

2008	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
Jan	0	0	0.00%
Feb	0	0	0.00%
Mar	1	1	100.00%
Apr	1	1	100.00%
May	1	1	100.00%
Jun	11	11	100.00%
Jul	12	12	100.00%
Aug	3	3	100.00%
Sep	1	1	100.00%
Oct	3	3	100.00%
Nov	0	0	0.00%
Dec	1	1	100.00%
Annual Total	34	34	100.00%

SERVICE RELIABILITY INDICES INCLUDING OUTAGES CAUSED BY LOSS OF SUPPLY (2008-2011)

2011	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	95	16	2756	0.03	0.01	5.94
Feb	16	20	2740	0.01	0.01	0.80
Mar	22	17	2739	0.01	0.01	1.29
Apr	243	183	2745	0.09	0.07	1.33
May	178	161	2741	0.06	0.06	1.11
Jun	123	90	2742	0.04	0.03	1.37
Jul	720	294	2739	0.26	0.11	2.45
Aug	616	544	2743	0.22	0.20	1.13
Sep	17247	3012	2746	6.28	1.10	5.73
Oct	430	208	2777	0.15	0.07	2.07
Nov	1500	251	2746	0.55	0.09	5.98
Dec	91	54	2760	0.03	0.02	1.69
Annual Total	21281	4850	2748	7.74	1.77	4.39

2010	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	6923	2752	2740	2.53	1.00	2.52
Feb	127	81	2742	0.05	0.03	1.57
Mar	1	5	2729	0.00	0.00	0.20
Apr	1074	544	2729	0.39	0.20	1.97
May	20725	5557	2735	7.58	2.03	3.73
Jun	202	235	2734	0.07	0.09	0.86
Jul	201	236	2745	0.07	0.09	0.85
Aug	474	197	2754	0.17	0.07	2.41
Sep	244	64	2753	0.09	0.02	3.81
Oct	35	34	2743	0.01	0.01	1.03
Nov	148	85	2766	0.05	0.03	1.74
Dec	10	8	2757	0.00	0.00	1.25
Annual Total	30164	9798	2744	10.99	3.57	3.08

2009	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	11	20	2733	0.00	0.01	0.55
Feb	125	218	2733	0.05	0.08	0.57
Mar	96	163	2741	0.04	0.06	0.59
Apr	20	46	2731	0.01	0.02	0.43
May	115	44	2757	0.04	0.02	2.61
Jun	144	83	2737	0.05	0.03	1.73
Jul	291	259	2728	0.11	0.09	1.12
Aug	29	31	2738	0.01	0.01	0.94
Sep	28	3	2742	0.01	0.00	9.33
Oct	10	4	2751	0.00	0.00	2.50
Nov	19	26	2743	0.01	0.01	0.73
Dec	0	1	2733	0.00	0.00	0.00
Annual Total	888	898	2739	0.32	0.33	0.99

2008	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	1	1	2749	0.00	0.00	1.00
Feb	0	0	2749	0.00	0.00	#DIV/0!
Mar	6	7	2739	0.00	0.00	0.86
Apr	2	3	2740	0.00	0.00	0.67
May	187	122	2734	0.07	0.04	1.53
Jun	205	134	2753	0.07	0.05	1.53
Jul	362	187	2749	0.13	0.07	1.94
Aug	75	72	2756	0.03	0.03	1.04
Sep	108	76	2750	0.04	0.03	1.42
Oct	199	93	2763	0.07	0.03	2.14
Nov	12	19	2758	0.00	0.01	0.63
Dec	0	1	2735	0.00	0.00	0.00
Annual Total	1157	715	2748	0.42	0.26	1.62

SERVICE RELIABILITY INDICES EXCLUDING OUTAGES CAUSED BY LOSS OF SUPPLY (2008-2011)

2011	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	95	16	2756	0.03	0.01	5.94
Feb	16	20	2740	0.01	0.01	0.80
Mar	22	17	2736	0.01	0.01	1.29
Apr	243	183	2745	0.09	0.07	1.33
May	178	161	2741	0.06	0.06	1.11
Jun	123	90	2742	0.04	0.03	1.37
Jul	720	294	2739	0.26	0.11	2.45
Aug	616	544	2743	0.22	0.20	1.13
Sep	661	266	2746	0.24	0.10	2.48
Oct	430	208	2777	0.15	0.07	2.07
Nov	1500	251	2746	0.55	0.09	5.98
Dec	91	54	2760	0.03	0.02	1.69
Annual Total	4695	2104	2748	1.71	0.77	2.23

2010	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	27	12	2740	0.01	0.00	2.25
Feb	127	81	2742	0.05	0.03	1.57
Mar	1	5	2729	0.00	0.00	0.20
Apr	1074	544	2736	0.39	0.20	1.97
May	121	87	2735	0.04	0.03	1.39
Jun	202	235	2734	0.07	0.09	0.86
Jul	201	236	2745	0.07	0.09	0.85
Aug	474	197	2754	0.17	0.07	2.41
Sep	44	14	2753	0.02	0.01	3.14
Oct	35	34	2743	0.01	0.01	1.03
Nov	148	85	2766	0.05	0.03	1.74
Dec	10	8	2757	0.00	0.00	1.25
Annual Total	2464	1538	2745	0.90	0.56	1.60

2009	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	11	20	2733	0.00	0.01	0.55
Feb	125	218	2733	0.05	0.08	0.57
Mar	96	163	2741	0.04	0.06	0.59
Apr	20	46	2731	0.01	0.02	0.43
May	115	44	2757	0.04	0.02	2.61
Jun	144	83	2737	0.05	0.03	1.73
Jul	291	259	2728	0.11	0.09	1.12
Aug	29	31	2738	0.01	0.01	0.94
Sep	28	3	2742	0.01	0.00	9.33
Oct	10	4	2751	0.00	0.00	2.50
Nov	19	26	2743	0.01	0.01	0.73
Dec	0	1	2733	0.00	0.00	0.00
Annual Total	888	898	2739	0.32	0.33	0.99

2008	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	1	1	2749	0.00	0.00	1.00
Feb	0	0	2749	0.00	0.00	#DIV/0!
Mar	6	7	2739	0.00	0.00	0.86
Apr	2	3	2740	0.00	0.00	0.67
May	187	122	2734	0.07	0.04	1.53
Jun	205	134	2753	0.07	0.05	1.53
Jul	362	187	2749	0.13	0.07	1.94
Aug	75	72	2756	0.03	0.03	1.04
Sep	108	76	2750	0.04	0.03	1.42
Oct	199	93	2763	0.07	0.03	2.14
Nov	12	19	2758	0.00	0.01	0.63
Dec	0	1	2735	0.00	0.00	0.00
Annual Total	1157	715	2748	0.42	0.26	1.62

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1	1		Overview of Operating Revenue
	2	1		Weather Normalized Load and Customer/ Connection Forecast
	2		3-A	Monthly Data Used for Regression Analysis
	3	1		Operating Revenue Variance Analysis.
	3	2		Transformer Allowance
	3	3		Variance Analysis on Other Distribution Revenue

OVERVIEW OF OPERATING REVENUE

This Exhibit provides the details of SLHI’s operating revenue for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, the 2012 Bridge Year and the 2013 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

SLHI is proposing a total Service Revenue Requirement of $2,091,430 for the 2013 Test Year. This amount includes a Base Revenue Requirement of $ 1,962,405 plus revenue offsets of $129,025 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3-1 and provides a comparison of total revenues from the 2008 OEB approved year to the 2013 Test Year.

Throughput Revenue:

Information related to SLHI's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on the historical throughput revenue is also provided in this Exhibit.

Other Revenue:

Other revenues include Standard Service Supply (SSS) Administration Charges, Rent from Electric Property, Late Payment Charges, Specific Service Charges and Other Income and Deductions.

A detailed variance analysis on other revenue is set out later on this Exhibit.

Table 3-1: Summary of Operating Revenue

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test at Current Rates	2013 Test at Proposed Rates
Distribution Throughput Revenue								
Residential	$985,990	$869,707	$1,049,004	$987,511	$1,010,129	$1,057,447	$1,040,067	$1,222,636
GS < 50	$325,469	$282,130	$339,855	$319,719	$302,586	$301,107	$296,199	$309,069
GS > 50	$426,978	$299,033	$308,481	$322,349	$330,432	$358,094	$350,336	$330,062
Street Lighting	$33,008	$12,195	$64,818	$89,984	$99,712	$101,742	$102,100	$100,028
Unmetered Scattered Load	$3,194	$3,124	$3,620	$3,305	$1,671	$356	$615	$674
Total	**$1,774,639**	**$1,466,188**	**$1,765,777**	**$1,722,868**	**$1,744,530**	**$1,818,746**	**$1,789,317**	**$1,962,469**
Other Distribution Revenue								
SSS Administration Revenue						$8,238	$8,265	$8,265
Rent from Electric property	$42,027	$38,630	$40,023	$40,279	$43,195	$42,027	$42,027	$42,027
Late Payment Charges	$54,000	$40,428	$50,000	$37,665	$38,119	$39,868	$39,868	$39,868
Specific Service Charges	$20,122	$24,855	$21,695	$19,435	$18,455	$16,741	$16,741	$16,741
Other Income or Deductions	$57,991	$135,809	$15,643	$21,103	$21,163	-$99,637	$22,124	$22,124
Total	**$174,140**	**$239,722**	**$127,361**	**$118,482**	**$120,932**	**$7,237**	**$129,025**	**$129,025**
Grand Total	**$1,948,779**	**$1,705,910**	**$1,893,138**	**$1,841,350**	**$1,865,462**	**$1,825,983**	**$1,918,342**	**$2,091,494**

The difference of $65 in the calculation of 2013 Test year revenue at the proposed rates is due to rounding.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by SLHI to prepare the weather normalized load and customer/connection forecast used to design the proposed 2013 electricity distribution rates.

In summary, SLHI has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, SLHI submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. SLHI has the data for the amount of electricity (in kWh) purchased from the IESO for use by SLHI's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to bill kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, Intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. During the review process of the 2009 cost of service applications, Intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly kWh by rate class. SLHI attempted to conduct the regression analysis on an individual rate class basis. However, based on the statistical information shown in the following table, SLHI concluded using the equation resulting from the individual rate class regression analysis would not provide a prediction formula that was as good as the prediction equation from the power purchased method. The power purchased method has slightly better R square and Adjusted R square values than any of the individual rate class cases at 82% and 81%, respectfully. The MAPE (Mean Absolute Percent

Error) on the annual value for the power purchased method is 2.0% compared to the MAPE values shown below for the individual class method. The regression analysis has indicated that only 2 or 3 explanatory variables have statistical significance for the individual classes.

Table 3-1: Statistical Information for Individual Class Regression Analysis			
Class	**Residential**	**GS<50**	**GS>50**
R Square	81%	77%	63%
Adjusted R Square	81%	76%	62%
MAPE (Mean Absolute Percent Error) on Annual Value	3.3%	3.3%	8.8%
Coefficients - Value			
Intercept	1,694,568	1,065,565	3,254,519
Heating Degree Days	2,317	748	965
Spring Fall Flag	(184,148)	(186,180)	
CDM Activity		(1.6)	(21.0)
Coefficients - t Stat			
Intercept	20.57	27.08	27.28
Heating Degree Days	20.93	16.54	6.17
Spring Fall Flag	(2.22)	(5.50)	
CDM Activity		(3.03)	(11.43)

During the review of 2010 cost of service applications, Board staff and Intervenors expressed concern that the regression analysis assigned coefficients to some variable that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased as the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management ("CDM") savings in the utility but in the view of Board staff and Intervenors this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. SLHI has attempted to address these concerns in the load forecast used in this Application. Based on the OEB's approval of this methodology in a number of previous cost of service applications, and based on the discussion that follows, SLHI submits that its load forecasting methodology is reasonable for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by SLHI in this Application.

Table 3-2: Summary of Load and Customer/Connection Forecast						
Year	**Billed (GWh)**	**Growth (GWh)**	**Percent Change**	**Customer/ Connection Count**	**Growth**	**Percent Change (%)**
Billed Energy (GWh) and Customer Count / Connections						
2008 Board Approved	98.2			3,288		
2003 Actual	91.4			3,274		
2004 Actual	88.7	(2.7)	(3.0%)	3,288	14	0.4%
2005 Actual	94.4	5.8	6.5%	3,300	12	0.4%
2006 Actual	92.1	(2.4)	(2.5%)	3,270	(30)	(0.9%)
2007 Actual	90.7	(1.4)	(1.5%)	3,282	12	0.4%
2008 Actual	76.8	(13.9)	(15.4%)	3,292	10	0.3%
2009 Actual	72.4	(4.3)	(5.6%)	3,284	(8)	(0.2%)
2010 Actual	71.1	(1.3)	(1.9%)	3,284	0	0.0%
2011 Actual	73.1	2.0	2.8%	3,281	(3)	(0.1%)
2012 Bridge	**72.8**	(0.3)	(0.3%)	3,284	3	0.1%
2013 Test	**73.3**	0.4	0.6%	3,287	3	0.1%

The information in the table above provides weather actual data from 2003 to 2011, while 2012 and 2013 are weather normalized. SLHI does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers are shown in Table 3-3 and customer usage is shown in Table 3-4, on a rate class basis.

Table 3-3: Billed Energy and Number of Customers / Connections by Rate Class

Year	Residential	GS<50	GS>50	Streetlights	USL	Total
Billed Energy (GWh)						
2008 Board Approved	33.4	15.9	48.3	0.5	0.02	98.2
2003 Actual	32.5	16.9	41.5	0.5	0.04	91.4
2004 Actual	32.3	16.6	39.3	0.5	0.04	88.7
2005 Actual	32.8	16.2	44.9	0.5	0.04	94.4
2006 Actual	31.5	14.9	45.2	0.5	0.04	92.1
2007 Actual	32.8	15.3	42.0	0.5	0.04	90.7
2008 Actual	33.6	15.2	27.4	0.5	0.04	76.8
2009 Actual	33.7	16.2	22.0	0.5	0.04	72.4
2010 Actual	31.2	14.2	25.2	0.5	0.04	71.1
2011 Actual	32.7	12.6	27.3	0.5	0.02	73.1
2012 Bridge	**33.7**	**12.5**	**26.2**	**0.5**	**0.01**	**72.8**
2013 Test	**35.0**	**12.5**	**25.3**	**0.5**	**0.01**	**73.3**
Number of Customers/Connections						
2008 Board Approved	2,301	399	43	533	12	3,288
2003 Actual	2,272	423	31	535	13	3,274
2004 Actual	2,279	427	32	537	13	3,288
2005 Actual	2,294	425	36	532	13	3,300
2006 Actual	2,279	407	38	533	13	3,270
2007 Actual	2,296	398	42	533	13	3,282
2008 Actual	2,310	396	41	532	13	3,292
2009 Actual	2,301	396	40	534	13	3,284
2010 Actual	2,303	395	45	532	9	3,284
2011 Actual	2,313	383	50	532	3	3,281
2012 Bridge	2,318	378	53	532	2	3,284
2013 Test	2,323	374	56	531	2	3,287

Table 3-4: Annual Usage per Customer/Connection by Rate Class					
Year	**Residential**	**GS<50**	**GS>50**	**Streetlights**	**USL**
Energy Usage per Customer/Connection (kWh per customer/connection)					
2008 Board Approved	14,531	39,952	1,123,917	896	2,065
2003 Actual	14,287	40,041	1,337,661	869	3,268
2004 Actual	14,154	38,761	1,229,528	876	3,268
2005 Actual	14,307	38,073	1,246,977	927	3,268
2006 Actual	13,801	36,715	1,188,180	917	3,268
2007 Actual	14,292	38,461	1,000,605	919	3,268
2008 Actual	14,540	38,343	669,364	929	3,268
2009 Actual	14,667	40,841	549,832	883	3,268
2010 Actual	13,538	35,925	560,111	881	3,996
2011 Actual	14,135	32,961	545,316	937	5,199
2012 Bridge	14,516	33,081	492,998	939	5,470
2013 Test	15,056	33,530	448,138	941	5,753
Annual Growth Rate in Usage per Customer/Connection					
2008 Board App. Vs. 2008 Actual	(0.1%)	4.2%	67.9%	(3.5%)	(36.8%)
2003 Actual					
2004 Actual	(0.9%)	(3.2%)	(8.1%)	0.8%	0.0%
2005 Actual	1.1%	(1.8%)	1.4%	5.8%	0.0%
2006 Actual	(3.5%)	(3.6%)	(4.7%)	(1.0%)	0.0%
2007 Actual	3.6%	4.8%	(15.8%)	0.2%	0.0%
2008 Actual	1.7%	(0.3%)	(33.1%)	1.1%	0.0%
2009 Actual	0.9%	6.5%	(17.9%)	(4.9%)	0.0%
2010 Actual	(7.7%)	(12.0%)	1.9%	(0.3%)	22.3%
2011 Actual	4.4%	(8.3%)	(2.6%)	6.4%	30.1%
2012 Bridge	2.7%	0.4%	(9.6%)	0.2%	5.2%
2013 Test	3.7%	1.4%	(9.1%)	0.2%	5.2%

LOAD FORECAST AND METHODOLOGY

SLHI's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, Ontario Real GDP and Pulp Mill Flag. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with independent variables that impact on purchased energy. The regression model uses monthly kWh and monthly values of independent variables from January 2000 to December 2011 to determine a prediction formula with coefficients for each independent variable. This provides 144 monthly data points which represent a reasonable data set for use in a regression analysis. Consistent with the approach used by many other distributors in their cost of service applications, SLHI submits that it is appropriate to review the impact of weather over the period January 2000 to December 2011 and then determine the average weather conditions over this period which would be applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, SLHI has also provided a sensitivity analysis showing the impact on the 2013 forecast of purchases assuming weather normal conditions are based on a 10-year average and a 20-year trend of weather data.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by SLHI to predict weather normal purchases for 2012 and 2013:

SLHI's Monthly Predicted kWh Purchases

= Heating Degree Days * 5119
+ Cooling Degree Days * 10,963
+ Ontario Real GDP Monthly % * 26,405
+ Pulp Mill Flag * 1,728,472
+ Intercept of 38,179

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from the Sioux Lookout weather station.

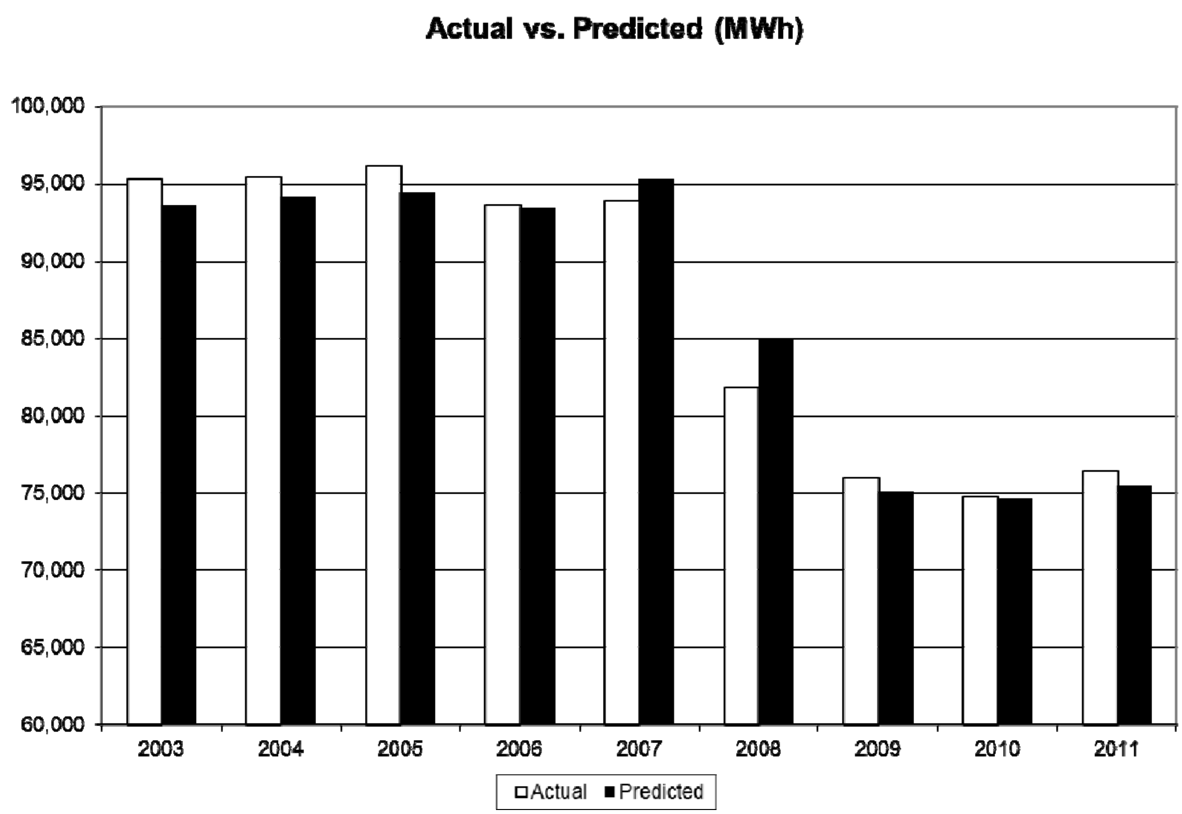
b) For 2000 to 2006 the source of data for the Ontario Real GDP information was the 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance. For 2007 and 2008, the source was the 2010 Ontario Economic Outlook and Fiscal Review - 2010 Fall Update. For 2009 to 2013, the 2011 Ontario Economic Outlook and Fiscal Review - 2011 Fall Update provided the Ontario Real GDP for those years.

c) The Pulp Mill Flag is set to “1” when the Pulp Mill was operational and set to “0” when the Pulp Mill was not operating. During the months from June 2010 to August 2010, the Pulp Mill was running at half capacity. For these months the flag was set to 0.5.

The prediction formula has the following statistical results:

Table 3-5: Statistcial Results	
Statistic	**Value**
R Square	82%
Adjusted R Square	81%
F Test	153.2
MAPE (Mean Absolute Percent Error) on Annual Value	2.0%
T-stats by Coefficient	
Intercept	0.0
Heating Degree Days	20.7
Cooling Degree Days	2.8
Ontario Real GDP Monthly %	2.3
Pulp Mill Flag	8.7

The annual results of the above prediction formula compared to the actual annual purchases from 2000 to 2011 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.



The following table outlines the data that supports the above chart. In addition, the predicted total system purchases for SLHI are provided for 2012 and 2013. For 2012 and 2013 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2013 are provided with a 10 year average and a 20 year trend assumption for weather normalization.

Table 3-6: Total System Purchases			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
2000	86.4	89.1	3.2%
2001	85.6	88.9	3.9%
2002	97.7	93.9	(3.8%)
2003	95.3	93.6	(1.8%)
2004	95.4	94.1	(1.3%)
2005	96.1	94.5	(1.7%)
2006	93.6	93.5	(0.1%)
2007	93.9	95.3	1.5%
2008	81.9	84.9	3.7%
2009	76.0	75.1	(1.3%)
2010	74.7	74.6	(0.1%)
2011	76.4	75.5	(1.2%)
2012 Weather Normal		**76.6**	
2013 Weather Normal		**77.6**	
2013 Weather Normal - 10 year average		**77.8**	
2013 Weather Normal - 20 year trend		**78.1**	

The weather normalized amount for 2013 is determined by using 2013 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2000 to December 2011 (i.e. 12 years). The 2013 weather normalized 10 year average value represents the average heating degree days and cooling degree days that occurred from January 2002 to December 2011. The 2013 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1992 to December 2011.

The weather normal 12 year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The 12 year average has been used as this is consistent with the period of time over which the regression analysis was conducted

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by SLHI using the average loss factor from 2003 to 2011 of 1.0446. With this average loss factor the total weather normalized billed energy will be 73.4 GWh for 2012 (i.e. 76.6/1.0446) and 74.3 GWh for 2013 (i.e. 77.6/1.0446) before adjustments for 2012 and 2013 CDM programs.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 3-7: Historical Customer/Connection Data

Year	Residential	GS<50	GS>50	Streetlights	USL	Total
Number of Customers/Connections						
2003	2,272	423	31	535	13	3,274
2004	2,279	427	32	537	13	3,288
2005	2,294	425	36	532	13	3,300
2006	2,279	407	38	533	13	3,270
2007	2,296	398	42	533	13	3,282
2008	2,310	396	41	532	13	3,292
2009	2,301	396	40	534	13	3,284
2010	2,303	395	45	532	9	3,284
2011	2,313	383	50	532	3	3,281

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2003 to 2011.

Table 3-8: Growth Rate in Customer/Connections					
Year	**Residential**	**GS<50**	**GS>50**	**Streetlights**	**USL**
Growth Rate in Customers/Connections					
2003					
2004	0.3%	0.9%	3.2%	0.4%	0.0%
2005	0.7%	(0.5%)	12.5%	(0.9%)	0.0%
2006	(0.7%)	(4.2%)	5.6%	0.2%	0.0%
2007	0.7%	(2.2%)	10.5%	0.0%	0.0%
2008	0.6%	(0.5%)	(2.4%)	(0.2%)	0.0%
2009	(0.4%)	0.0%	(2.4%)	0.4%	0.0%
2010	0.1%	(0.3%)	12.5%	(0.4%)	(30.8%)
2011	0.4%	(3.0%)	11.1%	0.0%	(66.7%)
Geometric Mean	**0.2%**	**(1.2%)**	**6.2%**	**(0.1%)**	**(16.7%)**

The resulting geometric mean was first applied to the actual 2011 customer/connection numbers to determine the forecast of customer/connections in 2012 and then again to the 2012 forecast to determine the 2013 forecast. The following table outlines the forecast of customers and connections by rate class.

Table 3-9: Customer/Connection Forecast						
Year	**Residential**	**GS<50**	**GS>50**	**Streetlights**	**USL**	**Total**
Forecast Number of Customers/Connections						
2012	**2,318**	**378**	**53**	**532**	**2**	**3,284**
2013	**2,323**	**374**	**56**	**531**	**2**	**3,287**

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2003 to 2011.

Table 3-10: Historical Annual Usage per Customer					
Year	**Residential**	**GS<50**	**GS>50**	**Streetlights**	**USL**
Annual kWh Usage Per Customer/Connection					
2003	14,287	40,041	1,337,661	869	3,268
2004	14,154	38,761	1,229,528	876	3,268
2005	14,307	38,073	1,246,977	927	3,268
2006	13,801	36,715	1,188,180	917	3,268
2007	14,292	38,461	1,000,605	919	3,268
2008	14,540	38,343	669,364	929	3,268
2009	14,667	40,841	549,832	883	3,268
2010	13,538	35,925	560,111	881	3,996
2011	14,135	32,961	545,316	937	5,199

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table 3-11: Growth Rate in Usage Per Customer/Connection					
Year	**Residential**	**GS<50**	**GS>50**	**Streetlights**	**USL**
Growth Rate in Customer/Connection					
2003					
2004	(0.9%)	(3.2%)	(8.1%)	0.8%	0.0%
2005	1.1%	(1.8%)	1.4%	5.8%	0.0%
2006	(3.5%)	(3.6%)	(4.7%)	(1.0%)	0.0%
2007	3.6%	4.8%	(15.8%)	0.2%	0.0%
2008	1.7%	(0.3%)	(33.1%)	1.1%	0.0%
2009	0.9%	6.5%	(17.9%)	(4.9%)	0.0%
2010	(7.7%)	(12.0%)	1.9%	(0.3%)	22.3%
2011	4.4%	(8.3%)	(2.6%)	6.4%	30.1%
Geometric Mean	**(0.1%)**	**(2.4%)**	**(10.6%)**	**0.9%**	**6.0%**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2011 usage and the resulting usage forecast is as follows:

Table 3-12: Forecast Annual kWh Usage per Customer/Connection					
Year	**Residential**	**GS<50**	**GS>50**	**Streetlights**	**USL**
Forecast Annual kWh Usage per Customers/Connection					
2012	**14,116**	**32,169**	**487,456**	**946**	**5,510**
2013	**14,098**	**31,396**	**435,736**	**955**	**5,839**

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3-9 by the forecast of annual usage per customer/connection from Table 3-12. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 3-13: Non-normalized Weather Billed Energy Forecast						
Year	**Residential**	**GS<50**	**GS>50**	**Streetlights**	**USL**	**Total**
NON-normalized Weather Billed Energy Forecast (GWh)						
2012 (Not Normalized)	**32.7**	**12.2**	**25.9**	**0.5**	**0.01**	**71.3**
2013 (Not Normalized)	**32.8**	**11.7**	**24.6**	**0.5**	**0.01**	**69.6**

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 73.4 GWh for 2012 and 74.3 GWh for 2013 before adjustments for 2012 and 2013 CDM programs.

The difference between the non-normalized and normalized forecast adjustments is 2.1 GWh in 2012 (i.e. 73.4 – 71.3) and 4.7 GWh in 2013 (i.e. 74.3 - 69.6). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for SLHI for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3-14: Weather Sensitivity by Rate Class

Residential	GS<50	GS>50	Streetlights	USL
Weather Sensitivity				
67.7%	67.7%	35.3%	0%	0%

For the GS > 50 kW class the weather sensitivity amount of 35.3% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. SLHI agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, SLHI has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 35.3%, or 67.7%.

The difference between the non-normalized and normalized forecast of 2.1 GWh in 2012 and 4.7 GWh in 2013 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

In addition a manual adjustment has been made to reflect the impact of 2012 and 2013 CDM programs on the load forecast. This adjustment reflects the "net" impact of 2012 and 2013 CDM programs on the load forecast.

The 2011 actual final savings from 2011 CDM programs are known and are assumed to be included in the regression analysis supporting the prediction formula since 2011 actual data is used in the analysis. However, knowing the 2011 results, impacts on what saving will be needed from 2012 to 2014 programs in order to achieve the licensed 4 year CDM target. Based on the following table the 2011 actual final savings will contribute 7.4% to the four year target. The table indicates that assuming persistence, 2012 to 2014 programs will need to achieve 15.4% of the four year target each year in order to achieve the target.

Table 3-15: Schedule to Achieve 4 Year kWh CDM Target					
4 Year 2011 to 2014 kWh target					
3,320,000					
	2011	2012	2013	2014	Total
2011 Programs	1.9%	1.9%	1.9%	1.8%	7.4%
2012 Programs		15.4%	15.4%	15.4%	46.3%
2013 Programs			15.4%	15.4%	30.9%
2014 Programs				15.4%	15.4%
	1.9%	17.3%	32.7%	48.1%	100.0%
kWh					
2011 Programs	61,496	61,496	61,496	61,229	245,717
2012 Programs		512,380	512,380	512,380	1,537,141
2013 Programs			512,380	512,380	1,024,761
2014 Programs				512,380	512,380
	61,496	573,877	1,086,257	1,598,370	3,320,000

The above table suggests that in 2012, the savings from 2012 program will be 512,380 kWh on a net basis. In SLHI's view, the 2012 load forecast should be adjusted by 512,380 kWh to reflect CDM savings from 2012 programs.

The above table also suggest that in 2013, the savings from 2012 and 2013 programs will be a 512,380 kWh times two or 1,024,760 kWh on a net basis. In SLHI's view, the 2013 load forecast should be adjusted by 1,024,760 kWh to reflect CDM savings from 2012 and 2013 programs.

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management [EB-2012-0003], issued by the Board on April 26, 2012, it is SLHI's understanding that as part of this application expected CDM savings in 2013 from 2011, 2012 and 2013 programs will need to be established for LRAM variance accounts purposes. It is also SLHI's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is SLHI's view the units used for the 2013 LRAM variance account should also be on a net basis. Based on the net information in table 3-15, SLHI expects to achieve 1,086,257 net kWh savings in 2013 from 2011 to 2013 CDM programs. For LRAM variance account purposes, the following table outlines how this expected savings has been allocated to rate class using the 2013 information from table 3-13. The expected kW saving has also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from Table 3-19

Table 3-16: 2013 Expected Savings for LRAM Variance Account						
	Residential	GS<50	GS>50	Streetlights	USL	Total
kWh	511,521	183,184	383,441	7,922	190	1,086,257
kW where applicable			967	24		991

The following table outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3-17: Alignment of Non-normal to Weather Normal Forecast						
Year	Residential	GS<50	GS>50	Streetlights	USL	Total
Non-normalized Weather Billed Energy Forecast (GWh)						
2012 Non-Normalized Bridge	32.7	12.2	25.9	0.5	0.01	71.3
2013 Non-Normalized Test	32.8	11.7	24.6	0.5	0.01	69.6
Weather Adjustment (GWh)						
2012	1.2	0.4	0.5	0.0	0.00	2.1
2013	2.7	1.0	1.1	0.0	0.00	4.7
CDM Adjustment (GWh)						
2012	(0.2)	(0.1)	(0.2)	(0.0)	(0.00)	(0.5)
2013	(0.5)	(0.2)	(0.4)	(0.0)	(0.00)	(1.0)
Weather Normalized Billed Energy Forecast (GWh)						
2012 Normalized Bridge	33.7	12.5	26.2	0.5	0.01	72.8
2013 Normalized Test	35.0	12.5	25.3	0.5	0.01	73.3

Billed KW Load Forecast

There are two rate classes that charge volumetric distribution on per kW basis. These include GS > 50 kW and Street lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 3-18: Historical Annual kW per Applicable Rate Class

Year	GS>50	Streetlights	Total
Billed Annual kW			
2003	103,221	1,462	104,683
2004	94,884	1,461	96,345
2005	104,253	1,470	105,723
2006	106,738	1,449	108,187
2007	105,960	1,447	107,407
2008	75,100	1,445	76,545
2009	56,741	1,445	58,186
2010	71,492	1,448	72,940
2011	66,653	1,446	68,099

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2003 to 2011.

Table 3-19: Historical kW/KWh Ratio per Applicable Rate Class		
Year	**GS>50**	**Streetlights**
Ratio of kW to kWh		
2003	0.2489%	0.3145%
2004	0.2412%	0.3107%
2005	0.2322%	0.2982%
2006	0.2364%	0.2965%
2007	0.2521%	0.2956%
2008	0.2736%	0.2924%
2009	0.2580%	0.3063%
2010	0.2836%	0.3091%
2011	0.2445%	0.2901%
Average 2003 to 2011	0.2523%	0.3015%

The average ratio was applied to the weather normalized billed energy forecast in Table 3-19 to provide the forecast of kW by rate class as shown below. The following table outlines the forecast of kW for the applicable rate classes.

Table 3-20: kW Forecast by Applicable Rate Class			
Year	**GS>50**	**Streetlights**	**Total**
Predicted Billed kW			
2012 Normalized Bridge	**66,018**	**1,505**	**67,523**
2013 Normalized Test	**63,706**	**1,507**	**65,213**

Table 3-21 provides a summary of the billing determinants by rate class that are used to develop the proposed rates.

Table 3-21: Summary of Forecast							
	2008 Board Approved	**2008**	**2009**	**2010**	**2011**	**2012 Weather Normalized Bridge**	**2013 Weather Normalized Test**
ACTUAL AND PREDICTED KWH PURCHASES							
Actual kWh Purchases		81,867,475	76,016,629	74,719,842	76,399,313		
Predicted kWh Purchases		84,881,537	75,056,901	74,641,012	75,456,844	76,629,985	77,608,528
% Difference of actual and predicted purchases			(1.3%)	(0.1%)	(1.2%)		
BILLING DETERMINANTS BY CLASS							
Residential							
Customers	2,301	2,310	2,301	2,303	2,313	2,318	2,323
kWh	33,435,195	33,587,664	33,747,939	31,178,902	32,694,600	33,651,737	34,980,266
GS<50							
Customers	399	396	396	395	383	378	374
kWh	15,941,009	15,183,848	16,172,932	14,190,567	12,624,003	12,513,525	12,526,981
GS>50							
Customers	43	41	40	45	50	53	56
kWh	48,328,431	27,443,928	21,993,284	25,204,983	27,265,781	26,167,747	25,251,296
kW	121,066	75,100	56,741	71,492	66,653	66,018	63,706
Street Lighting							
Connections	533	532	534	532	532	532	531
kWh	477,656	494,167	471,711	468,441	498,452	499,208	499,759
kW	1,475	1,445	1,445	1,448	1,446	1,505	1,507
USL							
Connections	12	13	13	9	3	2	2
kWh	24,781	42,486	42,486	35,962	15,597	13,662	11,962
Total							
Customer/Connections	3,288	3,292	3,284	3,284	3,281	3,284	3,287
kWh	98,207,072	76,752,093	72,428,352	71,078,855	73,098,433	72,845,879	73,270,262
kW from applicable classes	122,541	76,545	58,186	72,940	68,099	67,523	65,213

Appendix 3-A

Monthly Data Used for Regression Analysis

Appendix 3-A

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Pulp Mill Flag	Predicted Purchases
Jan-00	10,087,200	1110	0	113.21	1	10,439,979
Feb-00	8,487,288	794	0	113.73	1	8,835,095
Mar-00	7,879,163	628	0	114.25	1	7,995,560
Apr-00	6,672,709	499	0	114.77	1	7,349,585
May-00	5,918,304	215	2	115.30	1	5,936,839
Jun-00	5,762,134	154	1	115.83	1	5,624,023
Jul-00	5,512,830	52	50	116.36	1	5,655,230
Aug-00	5,525,685	53	24	116.90	1	5,388,412
Sep-00	5,615,427	213	0	117.43	1	5,957,865
Oct-00	6,501,093	359	0	117.97	1	6,716,920
Nov-00	7,721,474	629	0	118.52	1	8,115,399
Dec-00	10,687,541	1212	0	119.06	1	11,113,620
Jan-01	9,543,906	943	0	119.23	1	9,743,734
Feb-01	9,290,846	988	0	119.40	1	9,974,554
Mar-01	7,755,917	734	0	119.58	1	8,679,929
Apr-01	6,820,032	425	0	119.75	1	7,105,816
May-01	6,053,943	202	0	119.92	1	5,965,286
Jun-01	5,592,513	74	31	120.10	1	5,653,104
Jul-01	5,659,409	32	60	120.27	1	5,760,325
Aug-01	5,603,862	24	77	120.45	1	5,906,028
Sep-01	5,468,734	185	12	120.62	1	6,024,776
Oct-01	7,116,759	435	0	120.80	1	7,182,550
Nov-01	7,624,160	528	0	120.97	1	7,661,187
Dec-01	9,069,590	836	0	121.15	1	9,243,993
Jan-02	10,268,619	1026	0	121.50	1	10,226,053
Feb-02	8,801,175	809	0	121.86	1	9,124,723
Mar-02	9,761,700	933	0	122.22	1	9,770,523
Apr-02	7,719,437	540	0	122.59	1	7,765,752
May-02	8,872,684	359	3	122.95	1	6,878,973
Jun-02	6,366,499	88	39	123.31	1	5,902,565
Jul-02	6,173,846	3	112	123.68	1	6,275,967
Aug-02	6,005,492	31	33	124.04	1	5,557,638
Sep-02	6,379,489	134	24	124.41	1	6,006,072
Oct-02	7,704,230	560	0	124.78	1	7,928,533
Nov-02	9,247,837	753	0	125.14	1	8,925,722
Dec-02	10,360,145	876	0	125.51	1	9,563,076
Jan-03	11,108,358	1113	0	125.66	1	10,781,648
Feb-03	11,023,705	1042	0	125.81	1	10,421,537
Mar-03	9,374,434	825	0	125.95	1	9,316,620
Apr-03	7,355,645	482	0	126.10	1	7,563,647
May-03	6,064,757	165	0	126.24	1	5,947,427
Jun-03	6,572,130	57	39	126.39	1	5,825,987
Jul-03	6,166,740	17	50	126.54	1	5,745,760
Aug-03	6,379,974	30	85	126.68	1	6,202,065
Sep-03	6,501,216	174	14	126.83	1	6,163,189
Oct-03	7,696,177	426	1	126.98	1	7,313,879
Nov-03	8,777,003	713	0	127.12	1	8,771,193
Dec-03	8,269,123	858	0	127.27	1	9,521,430

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Pulp Mill Flag	Predicted Purchases
Jan-04	11,500,105	1245	0	127.53	1	11,508,367
Feb-04	9,539,214	830	0	127.80	1	9,391,958
Mar-04	9,255,139	750	0	128.06	1	8,986,832
Apr-04	7,933,577	490	0	128.32	1	7,662,355
May-04	6,632,498	361	0	128.59	1	7,007,453
Jun-04	6,267,799	136	2	128.85	1	5,886,798
Jul-04	6,058,439	41	44	129.12	1	5,871,592
Aug-04	6,556,035	124	5	129.38	1	5,877,481
Sep-04	6,302,346	121	13	129.65	1	5,949,189
Oct-04	6,980,708	387	0	129.92	1	7,175,660
Nov-04	8,465,635	586	0	130.19	1	8,201,912
Dec-04	9,933,041	1057	0	130.45	1	10,620,537
Jan-05	11,019,606	1156	0	130.74	1	11,134,459
Feb-05	11,047,479	844	0	131.03	1	9,544,503
Mar-05	9,475,152	816	0	131.33	1	9,410,910
Apr-05	7,237,069	358	0	131.62	1	7,075,668
May-05	6,525,179	261	0	131.91	1	6,585,317
Jun-05	6,294,419	58	41	132.20	1	6,006,155
Jul-05	6,737,648	34	87	132.50	1	6,390,227
Aug-05	6,045,039	59	42	132.79	1	6,038,211
Sep-05	6,430,027	153	19	133.09	1	6,269,053
Oct-05	8,077,501	374	2	133.38	1	7,229,975
Nov-05	9,672,323	681	0	133.68	1	8,782,503
Dec-05	7,581,154	917	0	133.98	1	9,996,888
Jan-06	10,131,969	870	0	134.25	1	9,763,584
Feb-06	10,721,551	982	0	134.53	1	10,347,281
Mar-06	8,783,080	704	0	134.81	1	8,929,479
Apr-06	7,480,018	328	0	135.08	1	7,011,057
May-06	6,590,105	214	15	135.36	1	6,599,794
Jun-06	6,134,899	40	30	135.64	1	5,880,752
Jul-06	6,778,431	30	95	135.92	1	6,548,561
Aug-06	5,860,080	22	36	136.20	1	5,869,669
Sep-06	6,419,329	187	8	136.48	1	6,417,016
Oct-06	8,393,497	473	0	136.76	1	7,797,618
Nov-06	9,426,677	637	0	137.04	1	8,645,590
Dec-06	6,850,205	836	0	137.33	1	9,674,277
Jan-07	14,119,378	1027	0	137.55	1	10,653,381
Feb-07	10,868,916	1025	0	137.78	1	10,652,213
Mar-07	8,892,721	730	0	138.01	1	9,149,663
Apr-07	7,904,780	483	0	138.23	1	7,887,203
May-07	5,870,493	191	4	138.46	1	6,443,296
Jun-07	5,847,586	59	39	138.69	1	6,159,444
Jul-07	6,204,926	28	86	138.92	1	6,516,641
Aug-07	5,861,607	63	31	139.15	1	6,104,471
Sep-07	6,506,948	173	4	139.38	1	6,369,520
Oct-07	6,984,955	361	0	139.61	1	7,303,105
Nov-07	8,001,392	696	0	139.84	1	9,024,046
Dec-07	6,821,178	1034	0	140.07	0	9,028,300

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Pulp Mill Flag	Predicted Purchases
Jan-08	11,503,910	1044	0	139.97	0	9,080,287
Feb-08	9,208,890	1016	0	139.86	0	8,932,637
Mar-08	7,671,793	849	0	139.76	0	8,073,965
Apr-08	5,764,075	506	0	139.65	0	6,315,381
May-08	5,252,521	342	0	139.55	0	5,472,582
Jun-08	5,368,685	105	5	139.44	1	6,043,259
Jul-08	5,788,420	41	23	139.34	1	5,909,544
Aug-08	5,783,724	25	49	139.23	1	6,108,290
Sep-08	4,776,645	176	8	139.13	1	6,425,727
Oct-08	5,371,779	384	0	139.02	0	5,674,748
Nov-08	8,111,934	675	0	138.92	0	7,159,555
Dec-08	7,265,099	1169	0	138.81	0	9,685,560
Jan-09	12,089,350	1174	0	138.39	0	9,700,997
Feb-09	8,873,805	890	0	137.97	0	8,238,623
Mar-09	6,938,222	786	0	137.54	0	7,691,554
Apr-09	5,637,576	465	0	137.13	0	6,041,382
May-09	5,455,495	344	0	136.71	0	5,408,894
Jun-09	4,330,246	124	32	136.29	0	4,618,642
Jul-09	4,381,937	72	2	135.87	0	4,013,621
Aug-09	4,062,717	69	21	135.46	0	4,199,043
Sep-09	4,495,746	63	27	135.05	0	4,220,416
Oct-09	6,209,036	465	0	134.63	0	5,973,562
Nov-09	6,154,276	498	0	134.22	0	6,133,690
Dec-09	7,388,223	1025	0	133.81	0	8,816,477
Jan-10	11,066,124	1018	0	134.14	0	8,790,382
Feb-10	8,314,898	862	0	134.47	0	7,999,536
Mar-10	6,523,675	531	0	134.81	0	6,315,452
Apr-10	5,173,000	324	0	135.14	0	5,265,629
May-10	4,272,142	196	13	135.47	0	4,761,132
Jun-10	4,937,182	83	7	135.81	0.5	4,988,364
Jul-10	4,946,503	4	59	136.14	0.5	5,165,278
Aug-10	4,852,669	42	74	136.48	0.5	5,524,334
Sep-10	4,714,401	234	0	136.81	0	4,849,655
Oct-10	5,901,217	337	0	137.15	0	5,385,306
Nov-10	7,411,913	614	0	137.49	0	6,810,143
Dec-10	6,606,118	998	0	137.83	0	8,785,802
Jan-11	12,613,918	1157	0	138.03	0	9,603,597
Feb-11	8,586,533	890	0	138.24	0	8,243,280
Mar-11	7,047,311	816	0	138.44	0	7,870,931
Apr-11	6,163,169	466	0	138.65	0	6,084,220
May-11	4,610,688	237	3	138.86	0	4,953,968
Jun-11	4,667,440	86	25	139.06	0	4,421,351
Jul-11	4,544,231	12	91	139.27	0	4,777,979
Aug-11	4,713,561	12	51	139.48	0	4,343,775
Sep-11	4,379,673	167	17	139.69	0	4,769,084
Oct-11	5,778,261	311	3	139.89	0	5,358,008
Nov-11	7,473,290	595	0	140.10	0	6,780,818
Dec-11	5,821,238	880	0	140.31	0	8,249,834

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Pulp Mill Flag	Predicted Purchases
Jan-12		1074	0	140.52	0	9,243,818
Feb-12		914	0	140.73	0	8,434,313
Mar-12		758	0	140.94	0	7,641,966
Apr-12		447	0	141.15	0	6,053,841
May-12		257	3	141.36	0	5,123,789
Jun-12		89	24	141.57	0	4,495,684
Jul-12		30	63	141.78	0	4,631,195
Aug-12		46	44	141.99	0	4,505,729
Sep-12		165	12	142.20	0	4,770,060
Oct-12		406	1	142.41	0	5,882,747
Nov-12		634	0	142.62	0	7,047,516
Dec-12		975	0	142.83	0	8,799,326
Jan-13		1074	0	143.13	0	9,312,763
Feb-13		914	0	143.42	0	8,505,523
Mar-13		758	0	143.72	0	7,715,449
Apr-13		447	0	144.02	0	6,129,604
May-13		257	3	144.31	0	5,201,840
Jun-13		89	24	144.61	0	4,576,031
Jul-13		30	63	144.91	0	4,713,846
Aug-13		46	44	145.21	0	4,590,692
Sep-13		165	12	145.50	0	4,857,343
Oct-13		406	1	145.80	0	5,972,358
Nov-13		634	0	146.10	0	7,139,463
Dec-13		975	0	146.41	0	8,893,616

OPERATING REVENUE VARIANCE ANALYSIS

THROUGHPUT REVENUE and OTHER OPERATING REVENUE

VARIANCE ANALYSIS ON THROUGHPUT REVENUE:

A summary of historical and forecast operating revenues is presented in Exhibit 3, Tab 1, Schedule 1, Table 3-1. A variance analysis for the other net operating revenue will be provided further in Tab 3 Schedule 2 of this Exhibit.

2008 Board Approved:

SLHI's Board Approved operating revenue in fiscal 2008 was $1,948,779. Throughput revenue was $1,774,639 or 91.1%. The remaining $174,140 is accounted for under other net operating revenue.

2008 Actual:

SLHI's actual operating revenue in fiscal 2008 was $1,705,910. Throughput revenue was $1,466,188 or 86.0% of total revenues. Other net operating revenue accounts for the remaining $239,722.

Comparison 2008 Actual to 2008 Board Approved – Throughput Revenue:

Table 3-22: Comparison 2008 Actual to 2008 Board Approved

Throughput Revenue	2008 Board Approved	2008 Actual	Difference $	Difference %
Residential	$985,990	$869,707	-$116,283	-11.79%
GS < 50 kW	$325,469	$282,130	-$43,339	-13.32%
GS 50 to 4,999 kW	$426,978	$299,033	-$127,945	-29.97%
Street Lighting	$33,008	$12,195	-$20,813	-63.05%
Unmetered Scattered Load	$3,194	$3,124	-$70	-2.21%
Total	$1,774,639	$1,466,188	-$308,451	-17.38%

SLHI's throughput revenue was 17.38% or $308,451 lower than the amounts approved in the 2008 Cost of Service Application primarily due to late implementation of the 2008 rates. The rates were approved in October 2008 and implemented in November 1, 2008. The Board allowed SLHI to recover lost revenue from July 1, 2008 to October 31, 2008 through a foregone revenue rate rider from November 1, 2008 until April 30, 2009. The total revenue forecasted to be collected from this rate rider was $153,321. The amount collected to December 31, 2008 was $18,753. SLHI was not allowed to recover rates from May 1, 2008 to June 30, 2008 which accounts for approximately $76,660 ($153,321/4 months x 2 months). This accounts for $211,228 of the variance.

The closure of the Pulp Mill in 2007 also affected the throughput revenue. The Mill was expected to become operational again and was therefore not removed from the 2008 test year forecast. The Mill closed in December 2007 and became operational for a short time from June 2008 to September 2008. This explains the volumetric difference of 45,966 kW in Table 3-23 below for the GS 50 to 4,999 kW Class and accounts for $132,295 ($2.8781 x 45,966) of the variance from Table 3-22.

Table 3-23 below compares the 2008 Board Approved billing quantities to the 2008 Actual quantities.

Table 3-23: Comparison 2008 Actual to 2008 Board Approved

	Customer Connections			kWh		kW		
Billing Quantities	**2008 Board Approved**	**2008 Actual**	**Difference**	**2008 Board Approved**	**2008 Actual**	**2008 Board Approved**	**2008 Actual**	**Volumetric Difference**
Residential	2,301	2,310	9	33,435,195	33,587,664			152,469
GS < 50 kW	399	396	-3	15,941,009	15,183,848			-757,161
GS 50 to 4,999 kW	43	41	-2	48,328,431		121,066	75,100	-45,966
Street Lighting	533	532	-1	477,656		1,475	1,445	-30
Unmetered Scattered Load	12	13	1	24,781	42,486			17,705
Total	3,288	3,292	4	98,207,072	48,813,998	122,541	76,545	

2009 Actual:

SLHI's operating revenue in fiscal 2009 was $1,893,138. Throughput revenue was $1,765,777 or 93.3% of total revenues. Other net operating revenue accounts for the remaining $127,361.

Comparison 2009 Actual to 2008 Actual – Throughput Revenue:

Table 3-24: Comparison 2009 Actual to 2008 Actual

Throughput Revenue	2008 Actual	2009 Actual	Difference $	Difference %
Residential	$869,707	$1,049,004	$179,297	20.62%
GS < 50 kW	$282,130	$339,855	$57,725	20.46%
GS 50 to 4,999 kW	$299,033	$308,481	$9,448	3.16%
Street Lighting	$12,195	$64,818	$52,623	431.52%
Unmetered Scattered Load	$3,124	$3,620	$496	15.88%
Total	$1,466,188	$1,765,777	$299,589	20.43%

SLHI's throughput revenue for 2009 was 20.43% or $299,589 higher than 2008 primarily due to the revenue collected from the foregone revenue rate rider for late implementation of the 2008 rates. The actual revenue collected from January 1 to April 30, 2009 was $120,716.

The increase in the Street Lighting class throughput revenue was due to increasing the revenue to cost ratio from 23.3 % in 2008 to 49.9% in 2009. Also, a portion of the difference is due to the foregone revenue rate rider collected for 2008.

The balance of the variance can be attributed to the rate increase approved in SLHI's 2008 rate rebasing application and the timing difference between fiscal and rate years.

Table 3-25 below compares the 2008 actual billing quantities to the 2009 actual billing quantities.

Table 3-25: Comparison 2009 Actual to 2008 Actual

	Customer Connections			kWh		kW		
Billing Quantities	**2008 Actual**	**2009 Actual**	**Difference**	**2008 Actual**	**2009 Actual**	**2008 Actual**	**2009 Actual**	**Volumetric Difference**
Residential	2,310	2,301	-9	33,587,664	33,747,939			160,275
GS < 50 kW	396	396	0	15,183,848	16,172,932			989,084
GS 50 to 4,999 kW	41	40	-1	27,443,928		75,100	56,741	-18,359
Street Lighting	532	534	2	494,167		1,445	1,445	0
Unmetered Scattered	13	13	0	42,486	42,486			0
Total	3,292	3,284	-8	76,752,093	49,963,357	76,545	58,186	

2010 Actual:

SLHI's operating revenue in fiscal 2010 was $1,841,350. Throughput revenue totaled $1,722,868 or 93.6% of total revenues. Other net operating revenue accounts for the remaining revenue of $118,482.

Comparison 2010 Actual to 2009 Actual – Throughput Revenue*:*

Table 3-26: Comparison 2010 Actual to 2009 Actual

Throughput Revenue	**2009 Actual**	**2010 Actual**	**Difference $**	**Difference %**
Residential	$1,049,004	$987,511	-$61,493	-5.86%
GS < 50 kW	$339,855	$319,719	-$20,135	-5.92%
GS 50 to 4,999 kW	$308,481	$322,349	$13,868	4.50%
Street Lighting	$64,818	$89,984	$25,166	38.82%
Unmetered Scattered Load	$3,620	$3,305	-$315	-8.71%
Total	$1,765,777	$1,722,868	-$42,910	-2.43%

The 2010 throughput revenue was $42,910 or 2.43% lower than the 2009 actual revenue. The variance is explained by the following.

First, the foregone revenue collected for 2008 late rate implementation ended April 30, 2009. As stated above the total revenue collected for this rate rider in 2009 was $120,716. When removing this amount from the 2009 revenue, there is an increase in total revenue of $77,807 in 2010.

Of the $77,807 increase, $36,689 was due to the Pulp Mill becoming operational at half capacity from June to August 2010. The Street Lighting increase in revenue of $25,166 is due to applying the final adjustment to the revenue to cost ratio in 2010 to bring it to 70%.

The remainder of the variance of is explained by the increase in rates for the 2010 IRM application.

Table 3-27 below compares the 2009 Actual billing quantities to the 2010 Actual quantities.

Table 3-27: Comparison 2010 Actual to 2009 Actual

	Customer Connections			kWh		kW		
Billing Quantities	2009 Actual	2010 Actual	Difference	2009 Actual	2010 Actual	2009 Actual	2010 Actual	Volumetric Difference
Residential	2,301	2,303	2	33,747,939	31,178,902			-2,569,037
GS < 50 kW	396	395	-1	16,172,932	14,190,567			-1,982,365
GS 50 to 4,999 kW	40	45	5	21,993,284		56,741	71,492	14,751
Street Lighting	534	532	-2	471,711		1,445	1,448	3
Unmetered Scattered Load	13	9	-4	42,486	35,962			-6,524
Total	3,284	3,284	0	72,428,352	45,405,431	58,186	72,940	

2011 Actual:

SLHI's operating revenue in fiscal 2011 was $1,865,462. Throughput revenue totaled $1,744,530 or 93.5% of total revenues. Other net operating revenue accounts for the remaining revenue of $120,932.

Comparison 2011 Actual to 2010 Actual Throughput Revenue:

Table 3-28: Comparison 2011 Actual to 2010 Actual				
Throughput Revenue	**2010 Actual**	**2011 Actual**	**Difference $**	**Difference %**
Residential	$987,511	$1,010,129	$22,619	2.29%
GS < 50 kW	$319,719	$302,586	-$17,133	-5.36%
GS 50 to 4,999 kW	$322,349	$330,432	$8,083	2.51%
Street Lighting	$89,984	$99,712	$9,728	10.81%
Unmetered Scattered Load	$3,305	$1,671	-$1,634	-49.43%
Total	$1,722,868	$1,744,530	$21,662	1.26%

Throughput revenue in 2011 was 1.26% or $21,662 higher than in 2010 due primarily to the 2011 IRM rate changes effective May 1, 2011.

The 10.81% increase in the Street Lighting revenue can be attributed to the timing difference of the 2010 rate implementation with the rate year of May 1, 2010.

Finally, the 49.43% decrease in the Unmetered Scattered Load revenue is explained by the decrease in the number of connections in this class from 9 in 2010 to 3 in 2011.

Table 3-29 below compares the 2010 Actual billing quantities to the 2011 Actual quantities.

Table 3-29: Comparison 2011 Actual to 2010 Actual								
	Customer Connections			**kWh**		**kW**		
Billing Quantities	**2010 Actual**	**2011 Actual**	**Difference**	**2010 Actual**	**2011 Actual**	**2010 Actual**	**2011 Actual**	**Volumetric Difference**
Residential	2,303	2,313	10	31,178,902	32,694,600			1,515,698
GS < 50 kW	395	383	-12	14,190,567	12,624,003			-1,566,564
GS 50 to 4,999 kW	45	50	5	25,204,983		71,492	66,653	-4,839
Street Lighting	532	532	0	468,441		1,448	1,446	-2
Unmetered Scattered Load	9	3	-6	35,962	15,597			-20,365
Total	3,284	3,281	-3	71,078,855	45,334,200	72,940	68,099	

2012 Bridge Year:

SLHI's operating revenue is forecast to be $1,825,983. Throughput revenue totals $1,818,746 or 99.6% of total revenues. Other net operating revenue accounts for the remaining revenue of $7,237.

Comparison 2012 Bridge to 2011 Actual Throughput Revenue:

Table 3-30: Comparison 2012 Bridge to 2011				
Throughput Revenue	**2011 Actual**	**2012 Bridge**	**Difference $**	**Difference %**
Residential	$1,010,129	$1,057,447	$47,318	4.68%
GS < 50 kW	$302,586	$301,107	-$1,479	-0.49%
GS 50 to 4,999 kW	$330,432	$358,094	$27,663	8.37%
Street Lighting	$99,712	$101,742	$2,030	2.04%
Unmetered Scattered Load	$1,671	$356	-$1,315	-78.70%
Total	$1,744,530	$1,818,746	$74,216	4.25%

Total throughput operating revenue is forecast to be 4.25% or $ 74,216 higher than the 2011 amounts.

Table 3-31 below compares 2011 Actual to 2012 Bridge billed quantities.

Table 3-31: Comparison 2012 Bridge to 2011 Actual								
	Customer Connections			kWh		kW		
Billing Quantities	**2011 Actual**	**2012 Bridge**	**Difference**	**2011 Actual**	**2012 Bridge**	**2011 Actual**	**2012 Bridge**	**Volumetric Difference**
Residential	2,313	2,318	5	32,694,600	33,651,737			957,137
GS < 50 kW	383	378	-5	12,624,003	12,513,525			-110,478
GS 50 to 4,999 kW	50	53	3	27,265,781		66,653	66,018	-635
Street Lighting	532	532	0	498,452		1,446	1,505	59
Unmetered Scattered Load	3	2	-1	15,597	13,662			-1,935
Total	3,281	3,283	2	73,098,433	46,178,924	68,099	67,523	

2013 Test Year:

SLHI's 2013 Test Year operating revenue is forecast to be $2,091,430. Throughput revenue totals $1,962,405 or 93.8.% of total revenues. Other net operating revenue accounts for the remaining revenue of $129,025.

Comparison of 2013 Test Year to 2012 Bridge Year Throughput Revenue:

Table 3-32: Comparison 2013 Test to 2012 Bridge				
Throughput Revenue	**2012 Bridge**	**2013 Test**	**Difference $**	**Difference %**
Residential	$1,057,447	$1,222,636	$165,189	15.62%
GS < 50 kW	$301,107	$309,069	$7,962	2.64%
GS 50 to 4,999 kW	$358,094	$330,062	-$28,032	-7.83%
Street Lighting	$101,742	$100,028	-$1,714	-1.68%
Unmetered Scattered Load	$356	$674	$318	89.33%
Total	$1,818,746	$1,962,469	$143,723	7.90%

Total throughput revenue is forecast to be $143,723 or 7.90% higher than the 2012 Bridge year. This variance is due to increased revenue resulting from this rate application.

Table 3-33 below compares the 2012 Bridge Year billing quantities to the 2013 Test Year billing quantities.

Table 3-33: Comparison 2013 Test to 2012 Bridge								
	Customer Connections			**kWh**		**kW**		
Billing Quantities	**2012 Bridge**	**2013 Test**	**Difference**	**2012 Bridge**	**2013 Test**	**2012 Bridge**	**2013 Test**	**Volumetric Difference**
Residential	2,318	2,323	5	33,651,737	34,980,266			1,328,529
GS < 50 kW	378	374	-4	12,513,525	12,526,981			13,456
GS 50 to 4,999 kW	53	56	3	26,167,747		66,018	63,706	-2,312
Street Lighting	532	531	-1	499,208		1,505	1,507	2
Unmetered Scattered Load	2	2	0	13,662	11,962			-1,700
Total	3,283	3,286	3	72,845,879	47,519,209	67,523	65,213	

TRANSFORMER ALLOWANCE

SLHI currently provides a Transformer Ownership Allowance Credit of .3741$/kW to those customers that own their own transformer facilities. SLHI is proposing to maintain this rate for the 2013 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE

2008 Board Approved Comparison to 2008 Actual – Other Operating Revenue:

Table 3-34 below summarizes the variance by account description.

Table 3-34: Comparison 2008 Actual to 2008 Board Approved				
Other Distribution Revenue	**2008 Board Approved**	**2008 Actual**	**Difference $**	**Difference %**
SSS Administration Revenue	$0	$0	$0	
Rent from Electric property	$42,027	$38,630	-$3,397	-8.08%
Late Payment Charges	$54,000	$40,428	-$13,572	-25.13%
Specific Service Charges	$20,122	$24,855	$4,733	23.52%
Other Income or Deductions	$57,991	$135,809	$77,818	134.19%
Subtotal	**$174,140**	**$239,722**	**$65,582**	**37.66%**
Deduct Deferral & Variance Account Interest		-$101,156	-$101,156	
Total	**$174,140**	**$138,566**	**-$35,574**	**-20.43%**

2009 Actual Comparison to 2008 Actual – Other Operating Revenue

Table 3-35 below summarizes the variance by account description.

Table 3-35: Comparison 2009 Actual to 2008 Actual				
Other Distribution Revenue	**2008 Actual**	**2009 Actual**	**Difference $**	**Difference %**
SSS Administration Revenue	$0	$0	$0	
Rent from Electric property	$38,630	$40,023	$1,393	3.61%
Late Payment Charges	$40,428	$50,000	$9,572	23.68%
Specific Service Charges	$24,855	$21,695	-$3,160	-12.71%
Other Income or Deductions	$135,809	$15,643	-$120,166	-88.48%
Subtotal	**$239,722**	**$127,361**	**-$112,361**	**-46.87%**
Deduct Deferral & Variance Account Interest	-$101,156	-$13,165	$87,991	
Total	**$138,566**	**$114,196**	**-$24,370**	**-17.59%**

The variance of -17.59% can be primarily explained by the decrease of the prime rate of interest from 2008 to 2009. SLHI earns monthly variable interest on its bank balance, therefore interest earned decreased by $26,656 from 2008 to 2009.

2010 Actual Comparison to 2009 Actual – Other Operating Revenue

Table 3-36 below summarizes the variance by account description.

Table 3-36: Comparison 2010 Actual to 2009 Actual

Other Distribution Revenue	2009 Actual	2010 Actual	Difference $	Difference %
SSS Administration Revenue	$0	$0	$0	
Rent from Electric property	$40,023	$40,279	$256	0.64%
Late Payment Charges	$50,000	$37,665	-$12,335	-24.67%
Specific Service Charges	$21,695	$19,435	-$2,260	-10.42%
Other Income or Deductions	$15,643	$21,103	$5,460	34.90%
Subtotal	**$127,361**	**$118,482**	**-$8,879**	**-6.97%**
Deduct Deferral & Variance Account Interest	-$13,165	-$7,062	$6,103	
Total	**$114,196**	**$111,420**	**-$2,776**	**-2.43%**

2011 Actual Comparison to 2010 Actual – Other Operating Revenue:

Table 3-37 below summarizes the variance by account description.

Table 3-37: Comparison 2011 Actual to 2010 Actual

Other Distribution Revenue	2010 Actual	2011 Actual	Difference $	Difference %
SSS Administration Revenue	$0	$0	$0	
Rent from Electric property	$40,279	$43,195	$2,916	7.24%
Late Payment Charges	$37,665	$38,119	$454	1.21%
Specific Service Charges	$19,435	$18,455	-$980	-5.04%
Other Income or Deductions	$21,103	$21,163	$60	0.28%
Subtotal	**$118,482**	**$120,932**	**$2,450**	**2.07%**
Deduct Deferral & Variance Account Interest	-$7,062	-$10,001	-$2,939	
Total	**$111,420**	**$110,931**	**-$489**	**-0.44%**

2012 Bridge Year Comparison to 2011 Actual – Other Operating Revenue:

Table 3-38 below summarizes the variance by account description.

Table 3-38: Comparison 2012 Bridge to 2011 Actual

Other Distribution Revenue	2011 Actual	2012 Bridge	Difference $	Difference %
SSS Administration Revenue	$0	$8,238	$8,238	
Rent from Electric property	$43,195	$42,027	-$1,168	-2.70%
Late Payment Charges	$38,119	$39,868	$1,749	4.59%
Specific Service Charges	$18,455	$16,741	-$1,714	-9.29%
Other Income or Deductions	$21,163	-$99,637	-$120,800	-570.81%
Sub Total	**$120,932**	**$7,237**	**-$113,695**	**-94.02%**
Deduct Deferral & Variance Account Interest	-$10,001	$9,389	$19,390	
Total	**$110,931**	**$16,626**	**-$94,305**	**-85.01%**

The 2012 Bridge year Other Income and deductions includes amounts related to account 4305 – Regulatory Debit in the amount of $98,889 relating to the entry for SLHI's change in capitalization and depreciation policy from CGAAP to MCGAAP. Also included in Other Income or Deductions was a debit entry for SLHI's Smart Meter Disposition of $21,711. This amount, along with $12,322 for Deferral & Variance Account Interest make up the $9,389 total shown in the 2012 Bridge year Deferral & Variance Account Interest.

Comparison to 2013 Test Year to 2012 Bridge Year– Other Operating Revenue:

Table 3-39 below summarizes the variance by account description.

Table 3-39: Comparison 2013 Test to 2012 Bridge

Other Distribution Revenue	2012 Bridge	2013 Test	Difference $	Difference %
SSS Administration Revenue	$8,238	$8,265	$27	
Rent from Electric property	$42,027	$42,027	$0	0.00%
Late Payment Charges	$39,868	$39,868	$0	0.00%
Specific Service Charges	$16,741	$16,741	$0	0.00%
Other Income or Deductions	-$99,637	$22,124	$121,761	-122.20%
Sub Total	**$7,237**	**$129,025**	**$121,788**	**1682.85%**
Deduct Deferral & Variance Account Interest	$9,389	-$10,500	-$19,889	
Total	**$16,626**	**$118,525**	**$101,899**	**612.89%**

See the above explanation for the 2012 Other Income or Deductions.

Exhibit	Tab	Schedule	Appendix	Contents
4 – Operating Costs				
	1			**Overview**
		1		Manager's Summary of Operating Costs
	2			**OM&A Costs**
		1		Departmental and Corporate OM&A Activities
		2		OM&A Detailed Costs Tables
		3		Variance Analysis on OM&A Costs
		4		Employee Compensation, Pension Expense and Post Retirement Benefits
		5		Charges to Affiliates for Services Provided
		6		Purchase of Products and Services from Non-Affiliates
		7		Depreciation, Amortization and Depletion
	3			**Income Tax, Large Corporation Tax**
		1		Tax Calculations
		2		Capital Cost Allowance (CCA)
	4			**Modified CGAAP**
		1		MCGAAP Impact on OM&A
		2		MCGAAP Impact on Depreciation
		3		MCGAAP Impact on Tax Calculations
	5			**Conservation and Demand Management (CDM) Costs**
				Appendices
			4-A	Sioux Lookout Hydro Purchasing Policy
			4-B	2011 Federal & Ontario Tax Return
			4-C	Notices of Assessment
			4-D	OPA 2011 Final Evaluation Report

OVERVIEW:

Manager's Summary of Operating Costs

The operating costs presented in this Exhibit represent the annual expenditures required to sustain SLHI's distribution operations. SLHI follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. Historically SLHI has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. As stated throughout this application, given the recent announcement by the Canadian Accounting Standards Board (AcSB) "In anticipation of future activities of the International Accounting Standards Board, the Canadian Accounting Standards Board decided at its September 2012 meeting to extend the deferral of the mandatory IRFS changeover date for entities with qualifying rate-regulated activities to January 1, 2014, SLHI will be deferring the changeover date to International Financial Reporting Standards (IFRS) to January 1, 2014. As such, SLHI's transition date is January 1, 2013. Therefore this application has been prepared using what has been termed "modified CGAAP" (MCGAAP). The actuals for 2008 through to 2011 have been prepared using CGAAP as historically done, and the 2012 Bridge year has been prepared using both CGAAP and MCGAAP, with the Test year 2013 prepared using MCGAAP. These modifications include updating the capitalization and depreciation policy to align with IFRS. A full explanation of the impact of the changes in the 2012 Test Year resulting from the changes in SLHI's capitalization and depreciation policy can be found in Exhibit 2, Tab 5.

SLHI has removed the non-regulatory expenses in the 2008 – 2011 historical actual, the 2012 Bridge year and 2013 Test Year.

SLHI's audited financial statements for the years 2009, 2010 and 2011 did not include any charitable contributions or fees paid to charitable organizations, but did include expenses related to the maintenance of sentinel lights. In order to provide a useful comparison to historical data these non-regulatory expenses have been removed from OM&A as illustrated in Table 4.1.

Table 4.1: OM&A Reconciliation to Audited Financial Statements				
	2008	**2009**	**2010**	**2011**
OM&A as per Audited Financial Statements	**1,087,971**	**1,078,520**	**1,109,785**	**1,110,054**
Add: Bank Charges (Categorized: Interest in Audited, Billing and Collecting - OEB)	60,765	60,242	50,655	45,528
Add: Sentinel light amortization (Categorized : Amortization in Audited F/S, Maintenance - OEB)	2,328	2,509	2,343	1,531
Less: Miscellaneous credit (Categorized: Revenue in Audited F/S, Miscellaneous Admin - OEB)	-4,086	-1,210	-1,835	-1,949
Add: Special Purpose Charge Expense			12,498	15,042
OM&A Expense Before Removal of Non-Regulated Expenses	**1,146,978**	**1,140,061**	**1,173,446**	**1,170,206**
Less: Sentinel Light expenses	-3,199	-4899	-4438	-4533
Less: Special Purpose Charge Expenses			-12498	-15042
OM&A Expense	**1,143,779**	**1,135,162**	**1,156,510**	**1,150,631**
*small differences due to rounding				

A summary of SLHI's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year (CGAAP) and the 2012 Test Year (MCGAAP) and 2013 Test Year (MCGAAP) , is provided in Table 4.2 below. A summary of the variances as required by the Filing Requirements for 2008 through 2013 is provided in Tables 4.3.

Table 4.2: Summary of OM&A Expenses

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 (MCGAAP)	2013 Test (MCGAAP)
Operations	$421,827	$426,324	$396,303	$493,191	$479,053	$539,851	$584,640	$628,363
Maintenance	87,281	91,130	94,702	116,678	106,053	320,616	320,616	201,605
Subtotal	**$509,108**	**$517,454**	**$491,005**	**$609,869**	**$585,106**	**$860,467**	**$905,256**	**$829,968**
Year over Year % increase (decrease)			-5.1%	24.2%	-4.1%	47.1%	54.7%	-8.3%
% Change (Test year vs Last Rebasing Year actual)								60.4%
Billing and Collecting	349,826	365,700	381,340	310,460	265,561	298,102	298,102	316,965
Administrative and General	260,892	263,826	267,718	240,621	319,541	386,819	391,805	407,460
Subtotal	**$610,718**	**$629,526**	**$649,058**	**$551,081**	**$585,102**	**$684,921**	**$689,907**	**$724,425**
Year over Year % increase (decrease)			3.1%	-15.1%	6.2%	17.1%	17.9%	5.0%
% Change (Test year vs Last Rebasing Year actual)								15.1%
Total OM&A Expense	**$1,119,826**	**$1,146,980**	**$1,140,063**	**$1,160,950**	**$1,170,208**	**$1,545,388**	**$1,595,163**	**$1,554,393**
Year over Year % increase (decrease)			-0.6%	1.8%	0.8%	32.1%	36.3%	-2.6%

SLHI is proposing recovery of 2013 Test Year OM&A costs, excluding amortization, PILs and Interest totaling $1,549,433($1,554,393 less non-regulatory expenses).

Table 4.3 Summary OM&A Expense Variances

	Last Rebasing Year (2008 BA)	Last Rebasing Year (2008 Actuals)	Variance 2008 BA – 2008 Actuals	2009 Actuals	Variance 2009 Actuals vs. 2008 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2013 Test Year	Variance 2013 Test vs. 2012 Bridge
Operations	$ 421,827	$ 426,324	-$ 4,497	$ 396,303	-$ 30,021	$ 493,191	$ 96,888	$ 479,053	-$ 14,138	$ 584,640	$ 105,587	$ 628,363	$ 43,723
Maintenance	$ 87,281	$ 91,130	-$ 3,849	$ 94,702	$ 3,572	$ 116,678	$ 21,976	$ 106,053	-$ 10,625	$ 320,616	$ 214,563	$ 201,605	-$119,011
Billing and Collecting	$ 349,826	$ 365,700	-$ 15,874	$ 381,340	$ 15,640	$ 310,460	-$ 70,880	$ 265,561	-$ 44,899	$ 298,102	$ 32,541	$ 316,965	$ 18,863
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 260,892	$ 263,826	-$ 2,934	$ 267,718	$ 3,892	$ 240,621	-$ 27,097	$ 319,541	$ 78,920	$ 391,805	$ 72,264	$ 407,460	$ 15,655
Total OM&A Expenses	$ 1,119,826	$ 1,146,980	-$ 27,154	$ 1,140,063	-$ 6,917	$ 1,160,950	$ 20,887	$ 1,170,208	$ 9,258	$ 1,595,163	$ 424,955	$ 1,554,393	-$ 40,770
Variance from previous year				-$ 6,917		$ 20,887		$ 9,258		$ 424,955		-$ 40,770	
Percent change (year over year)				-1%		2%		1%		36%		-3%	
Percent Change: Test year vs. Most Current Actual								32.83%					
Simple average of % variance for all years								0%					7%
Compound Annual Growth Rate for all years												5.2%	
Compound Growth Rate (2011 Actuals vs. 2008 Actuals)								2.03%					

The table below sets out the OM&A cost per customer and Full Time equivalent employees.

Table 4.10 – OM&A Per Customer and FTE

	Last Rebasing Year (2008 Board-Approved)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MCGAAP	MCGAAP
Number of Customers	2,757	2,736	2,742	2,765	2,760	2,753	2,757
Total Recoverable OM&A from Appendix 2-I	$ 1,119,826	$ 1,146,980	$ 1,140,063	$ 1,160,950	$ 1,170,208	$ 1,595,163	$ 1,554,393
OM&A cost per customer	$406.18	$419.22	$415.78	$419.87	$423.99	$579.43	$563.80
Number of FTEEs	7	8	8	8	8	8.37	9
Customers/FTEEs	393.86	342.00	342.75	345.63	345.00	328.91	306.33
OM&A Cost per FTEE	$159,975.14	$143,372.50	$142,507.88	$145,118.75	$146,276.00	$190,581.00	$172,710.33

The number of customers includes the average number of residential, GS<50 and GS>50 customers as found in SLHI's Load Forecast.

Detailed information with respect to OM&A costs, arranged by USoA account, is provided in Exhibit 4, Tab 2, Schedule 2. Detailed information with respect to OM&A variances, arranged by USoA account, is provided in Exhibit 4, Tab 2, Schedule 3.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million. Therefore an analysis of all variances of $50,000 and greater has been provided.

OM&A Costs:

OM&A costs in this Exhibit represent SLHI's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to SLHI's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2013 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

OM&A Budgeting Process:

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year, and provides a plan against which actual results are evaluated. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget also needs to be approved by the Board of Directors.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work Plans:

Each Department Manager provides input for the preparation of the departmental budget. The following directives are provided to each manager and director:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budget as the base;
- Significant variances in spending from prior years must be explained and documented;
- Review the head count of the department for accuracy and outline any changes;
- Accounting prepares a total labour budget by department using projected wage and benefit costs. Overtime and account distribution are based on previous years actual plus any identified changes for the future year;

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

SLHI is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Please refer to Exhibit 4, Tab 3, Schedule 1 and Appendix 4-B for further tax calculations and a copy of the 2011 Federal tax return.

One-Time Costs

SLHI incurred costs in 2012 related to a confidential human resource issue in the amount of $84,746. SLHI proposes to collect the costs over four years, therefore $21,187 has been included in the 2013 Test Year OM&A expenses.

Regulatory Costs

The estimated regulatory costs for completing this application have been divided over two years. Table 4.12 provides these details as well as other regulatory expenses.

External incremental costs relating to the 2013 Cost of Service Rate Application process are projected to total $77,245 ($42,245 – 2012, $35,000 - 2013).These costs include consulting costs as well as anticipated Board and Intervenor expenses. These costs have been spread over a four year period beginning with the 2013 OM&A budget. The expenses relating to the 2013 cost of service application are included in OM&A for 2013 at 25% of the total costs for 2012 and 2013. The costs that have been included in Table 4.13 are indicated below:

Table 4.12 - Regulatory Costs

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2008 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 13,000	$ 12,900	$ 12,537	-2.81%	$ 12,734	1.57%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going						
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going		$ 529	$ 1,000	89.01%	$ 1,000	0.00%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters	5655		On-Time						
6	Consultants' costs for regulatory matters	5655		On-Time	$ 25,000	$ -	$ 40,000		$ 30,000	-25.00%
7	Operating expenses associated with staff resources allocated to regulatory matters	5610		On-Going	$ 41,921	$ 56,745	$ 62,840	10.74%	$ 67,353	7.18%
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments	5680		On-Going	$ 2,185	$ 2,516	$ 2,501	-0.61%	$ 2,501	0.00%
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		On-Time	$ -		$ 2,245		$ 5,000	122.71%
12	Sub-total - Ongoing Costs [3]		$ -		$ 57,106	$ 72,690	$ 78,878	8.51%	$ 83,588	5.97%
13	Sub-total - One-time Costs [4]		$ -		$ 25,000	$ -	$ 42,245		$ 35,000	-17.15%
14	Total		$ -		$ 82,106	$ 72,690	$ 121,123	66.63%	$ 118,588	-2.09%

Table 4.13 – One-Time Costs Associated with the 2013 Cost of Service Rate Application

	Historical Year(s)	2012 Bridge Year	2013 Test Year	Annualized 2013 Test Year
Expert Witness costs for regulatory matters				
Consultants' costs for regulatory matters		40,000	30,000	17,500
Operating expenses associated with staff resources allocated to regulatory matters				
Operating expenses associated with other resources allocated to regulatory matters 1				
Intervenor costs		2,245	5,000	1,812

Low Income Assistance Program (LEAP)

SLHI has included $2,455 of expense for the Low Income Assistance Program (LEAP) under Community Relations. This amount is based on 0.12% of the 2013 Test year Revenue Requirement, rounded.

Charitable Contributions

SLHI has not included any charitable donations in OM&A expenses for 2013.

Green Energy Act

Exhibit 2 of this application provides SLHI's plan for capital spending under the Green Energy Act. SLHI has not included any operating expenses related to the Green Energy Act in this application. SLHI does intend to record any incremental operating expenses related to the Green Energy Act in the prescribed deferral account.

Inflation in 2012 Bridge and 2013 Test Year

The 2012 Bridge Year forecast is based on actual expenses as of June 30, 2012 plus expected expenditures for the remaining 6 months. An inflation rate of 2.2% has been applied to the expected expenditures except in cases where it is a known amount, such as increase to wages for union staff according to the collective agreement. In the 2013 Test Year expenses have been budgeted based on existing prices and increases if known.

OM&A COSTS

Departmental and Corporate OM&A Activities

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5096) and maintenance (5105-5195) of SLHI's electrical system. This includes both direct labour costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering and Stores. SLHI's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions. SLHI's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with SLHI's capital project work so that where maintenance programs have identified matters which require capital investments, SLHI may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the distribution system. These activities include transformer oil analysis, planned visual inspections and routine line patrols. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted load break switch maintenance and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. SLHI constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by SLHI for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Metering:

The metering department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

STORES/WAREHOUSE

Stores area is shared duties of other departments and is accountable for managing the procurement, control, and movement of materials within SLHI's service centre. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

GARAGE/TRANSPORTATION FLEET

This area is shared duties of other departments and assists with the maintenance and control of approximately 6 fleet vehicles. Its objectives include keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard "cost per hour" is set for all vehicles within the fleet. Costs are adjusted to actual at year end.

LABOUR BURDEN

This department collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments, capital and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

CUSTOMER SERVICE

The Customer Service group is responsible for the customer care activities for the approximately 2,757 customers in SLHI's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. SLHI aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are reported in accounts 5305 to 5340.

Meter Reading:

Prior to June 2010 meter reading services were conducted by SLHI's meter reader. The transition to fully electronic meter reading in conjunction with TOU billing was completed in September 2011. SLHI still requires manual reads for GS > 50 kW customers.

Billing:

SLHI performs monthly billing and issues 32,988 electricity invoices annually to customers. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes (verification, estimation and edit); Electronic Billing Transactions (EBT) and retailer settlement functions for 75 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. SLHI offers customers a number of billing and payment options including walk-in counter service, an equal payment plan and a preauthorized payment plan.

Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In an effort to minimize credit losses, SLHI enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. SLHI also contracts an independent third party to place phone calls to active overdue accounts on a weekly basis. Final bill collections are turned over to a collection agency after collection methods are exhausted.

Community Relations:

SLHI is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. SLHI maintains a presence in the communities it serves, where staff is available to answer customer questions in a friendly environment. Due the small size of the utility, employees regularly perform multiple functions within their day to day tasks. Community Relations is integrated within the Billing and Collecting and Administration departments. Therefore costs related to Community Relations are not tracked separately.

Since LDCs are the "face-to-the-customer" for the electricity industry, SLHI has an important role to play in educating the public about electricity safety and energy conservation. SLHI continues to participate with the OPA in administering programs directed at Energy Conservation.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within SLHI, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- Management (5610)
- General Administrative Services (5615)

Executive Salaries and Expenses (5605) and Management Salaries and Expenses (5610)

These accounts include expenses for Executive Management and Management including salaries and related expenses. Consistent with Section 6-4 of the 2006 EDR Handbook and section 2.7.4 of the Chapter 2 Filing Requirements For Electricity Transmission and Distribution Applications which state that… "Where there are three or fewer, full time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer FTEs." Therefore, SLHI has aggregated account 5605 and 5610 with account 5615.

General Administrative Salaries and Expenses: 5615

Administrative Services is comprised of several sub-accounts: Accounting/Finance, Corporate Administration and Personnel Administration. The Finance department is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing SLHI, including development and preparation of rate filings, performance reporting, and compliance.

The Corporate Administration and Personnel Administration department is responsible for providing support services required to operate an effective corporation as well as human resource-related support services.

Expenses included in Administrative Services include salary and related payroll burdens associated with the Accounting & Regulatory Clerk, as well as incidental expenses relating to corporate services support and human resource support.

In addition, the cost of Safety and Health is included in this department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. SLHI is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category.

Miscellaneous General Expense: 5665

Membership dues, including dues relating to the Electrical Distributor Association, Board of Directors remuneration and expenses and other miscellaneous costs are included in this account.

Electrical Safety Authority (“ESA”): 5680

Expenses under Electrical Safety Authority (“ESA”) fees include all annual charges from the ESA.

OM&A Detailed Cost Tables

Table 4.20: Detailed Variance Analysis - Operations Expenses

Account	Description	Last Board-approved Rebasing year (2008 year)	Most Current Actuals Year 2011	Test Year 2013	Test Year versus Last Rebasing		Test Year versus Most current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	MCGAAP				
Operations								
5005	Operation Supervision and Engineering					-		-
5010	Load Dispatching					-		-
5012	Station Buildings and Fixtures Expense					-		-
5014	Transformer station Equipment - Operation Labour					-		-
5015	Transformer Station Equipment - Operation Supplies and Expenses					-		-
5016	Distribution Station Equipment - Operation Labour					-		-
5017	Distribution Station Equipment - Operation Supplies and Expenses					-		-
5020	Overhead Distribution Lines and Feeders - Operations Labour	$305,170	$399,013	$474,385	$169,215	55.45%	$75,372	18.89%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$77,500	$38,881	$84,010	$6,510	8.40%	$45,129	116.07%
5030	Overhead Sub-transmission Feeders - Operation					-		-
5035	Overhead Distribution - Transformers - Operation	$10,000			-$10,000	-100.00%		-
5040	Underground Distribution Lines and Feeders - Operation Labour					-		-
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses					-		-
5050	Underground Sub-transmission Feeders - Operation					-		-
5055	Underground Distribtuion Transformers - Operation					-		-
5060	Street lighting and Signal System Expense					-		-
5065	Meter Expense	$9,000	$0	$0	-$9,000	-100.00%		-
5070	Customer Premises - Operation Labour					-		-
5075	Customer Premises - Operation Materials and Expense					-		-
5085	Miscellaneous Distribution Expense	$20,157	$41,159	$69,968	$49,811	247.12%	$28,809	69.99%
5090	Underground Distribution Lines and Feeders - Rental Paid					-		-
5095	Overhead Distribution Lines and Feeders - Rental Paid					-		-
5096	Other Rent					-		-
Total Operations		**$421,827**	**$479,053**	**$628,363**	**$206,536**	**48.96%**	**$149,310**	**31.17%**

Table 4.21: Detailed Variance Analysis - Maintenance Expenses								
		Last Board-approved Rebasing year (2008 year)	Most Current Actuals Year 2011	Test Year 2013	Test Year versus Last Rebasing		Test Year versus Most current Actuals	
Account	Description				Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	MCGAAP				
Maintenance								
5105	Maintenance Supervision and Engineering					-		-
5110	Maintenance of Buildings and Fixtures - Distribution Stations					-		-
5112	Maintenance of Tranfromer Station Equipment					-		-
5114	Maintenance of Distribution Station Equipment					-		-
5120	Maintenance of Poles Towers and Fixtures	$26,517	$27,278	$48,730	$22,213	83.77%	$21,452	78.64%
5125	Maintenance of Overhead Conductors and Devices					-		-
5130	Maintenance of Overhead Services					-		-
5135	Overhead Distribution Lines and Feeders - Right of Way	$40,000	$68,170	$61,200	$21,200	53.00%	-$6,970	-10.22%
5145	Maintenance of Underground Conduit					-		-
5150	Maintenance of Undergroung Conductors and Devices					-		-
5155	Maintenance of Underground Services					-		-
5160	Maintenance of Line Transformers	$10,000	$2,114	$13,774	$3,774	37.74%	$11,660	551.56%
5165	Maintenance of Street Lighting and Signal Systems					-		-
5170	Sentinel Lights - Labour	$2,374	$2,156	$2,000	-$374	-15.75%	-$156	-7.24%
5172	Sentinel Lights - Materials and Expenses	$2,000	$2,377	$2,960	$960	48.00%	$583	24.53%
5175	Maintenance of Meters	$6,390	$3,958	$72,941	$66,551	1041.49%	$68,983	1742.88%
5178	Customer Installations Expenses - Leased Property					-		-
5195	Maintenance of Other Installations on Customer Premises					-		-
Total Maintenance		**$87,281**	**$106,053**	**$201,605**	**$114,324**	**130.98%**	**$95,552**	**90.10%**

Table 4.22: Detailed Variance Analysis - Billing and Collecting Expenses								
		Last Board-approved Rebasing year (2008 year)	Most Current Actuals Year 2011	Test Year 2013	Test Year versus Last Rebasing		Test Year versus Most current Actuals	
Account	Description				Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	MCGAAP				
Billing and Collecting								
5305	Supervision					-		-
5310	Meter Reading Expenses	$80,658	$5,251	$4,876	-$75,782	-93.95%	-$375	-7.14%
5315	Customer Billing	$162,865	$160,281	$195,212	$32,347	19.86%	$34,931	21.79%
5320	Collecting	$86,006	$90,179	$96,877	$10,871	12.64%	$6,698	7.43%
5325	Collecting - Cash Over and Short	-$3	-$146	$0	$3	-100.00%	$146	-100.00%
5330	Collection Charges	$300	$0	$0	-$300	-100.00%		-
5335	Bad Debt Expense	$20,000	$9,996	$20,000		-	$10,004	100.08%
5340	Miscellaneous Customer Accounts Expenses					-		-
Total Billing and Collecting		**$349,826**	**$265,561**	**$316,965**	**-$32,861**	**-9.39%**	**$51,404**	**19.36%**

Table 4.23: Detailed Variance Analysis - Administrative and General Expenses

Account	Description	Last Board-approved Rebasing year (2008 year)	Most Current Actuals Year 2011	Test Year 2013	Test Year versus Last Rebasing		Test Year versus Most current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	MCGAAP				
Administration and General Expense								
5605	Executive Salaries and Expenses					-		-
5610	Management Salaries and Expenses					-		-
5615	General Administrative Salaries and Expenses	$138,859	$179,236	$244,923	$106,064	76.38%	$65,687	36.65%
5620	Office Supplies and Expenses	$8,600	$8,627	$7,103	-$1,497	-17.41%	-$1,524	-17.67%
5625	Administrative Expense Transferred - Credit					-		-
5630	Outside Serives Employed	$30,683	$37,652	$36,773	$6,090	19.85%	-$879	-2.33%
5635	Property Insurance	$26,700	$18,470	$18,850	-$7,850	-29.40%	$380	2.06%
5640	Injuries and Damages					-		-
5645	OMERS Pensions and Benefits					-		-
5646	Employee Pensions and OPEB					-		-
5647	Employee Sick Leave					-		-
5650	Franchise Requirements					-		-
5655	Regulatory Expenses	$13,000	$13,429	$33,046	$20,046	154.20%	$19,617	146.08%
5660	General Advertising Expenses	$1,000	$3,820	$1,061	$61	6.10%	-$2,759	-72.23%
5665	Miscellaneous General Expenses	$20,815	$23,166	$40,882	$20,067	96.41%	$17,716	76.47%
5670	Rent	$19,050	$17,969	$19,866	$816	4.28%	$1,897	10.56%
5672	Lease Payment Charge					-		-
5675	Maintenance of General Plant					-		-
5680	Electrical Safety Authority Fees	$2,185		$2,501	$316	14.46%	$2,501	-
5681	Special Purpose Charge Expense		$15,042			-	-$15,042	-100.00%
5685	Independent Electricity System Operatior Fees and Penalties					-		-
5695	OM&A Control Account					-		-
6205	Donations					-		-
6205	Donations - Sub Account LEAP funding		$2,130	$2,455	$2,455	-	$325	15.26%
Total Administrative and General Expenses		**$260,892**	**$319,541**	**$407,460**	**$146,568**	**56.18%**	**$87,919**	**27.51%**
Total OM&A		**$1,119,826**	**$1,170,208**	**$1,554,393**	**$434,567**	**38.81%**	**$384,185**	**32.83%**
Adjustments for non-recoverable Items								
5681	Special Purpose Charge Expense		15042		$0	-	-$15,042	-100.00%
6205	Donations				$0	-	$0	-
5170	Sentinel Lights - Labour	2374	2156	2000	-$374	-15.75%	-$156	-7.24%
5172	Sentinel Lights - Materials and Expenses	2000	2377	2960	$960	48.00%	$583	24.53%
Total Recoverable OM&A		**$1,115,452**	**$1,150,633**	**$1,549,433**	**$433,981**	**38.91%**	**$398,800**	**34.66%**

Note: Accounts 5605 and 5610 have been aggregated with account 5615.

Variance Analysis on OM&A Costs

SLHI has provided a detailed OM&A expense analysis covering the periods from SLHI's last cost of service application. An analysis of expense changes by cost driver is provided in Table 4.25 with explanations below.

Table 4.25: Cost Driver Table

OM&A	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MCGAAP	MCGAAP
Opening Balance	1,119,826	1,146,980	1,140,063	1,160,950	1,170,208	1,595,163
Distribution Expenses - Maintenance	-11,157					7,343
Tree Trimming	14,678		10,560			
Maintenance of Meters - Smart Meters					78,832	
Distribution Expenses - Operations	16,823	-20,954	62,269		16,401	
Meter Revarification costs	-8,503					
Training Costs	-6,162			25,973	-25,000	27,650
Transformer Testing		-11,088	35,888	-37,139	17,567	
Customer Billing/Collecting	13,783		-10,992		17,981	
Bad Debt Expense		13,277	-9,361	-12,881		
Meter Reading Expense			-48,629	-22,360		
Amounts transferred from Acct 1556					116,682	-116,682
Management/General Admin Salaries/Expenses		19,061		13,205		
Regulatory Expenses		-15,221			42,245	-22,933
One Time Costs						21,187
2010 Audit fees not accrued			-16,808	33,616		
New Capitalization Policy					39,127	
Asset Management Plan Consulting fees					10,000	-10,000
Persisting due to Organizational restructuring					73,279	89,458
Succession Planning/Implementation					36,144	-36,144
Miscellaneous	7,692	8,008	-2,040	8,844	1,697	-649
Closing Balance	**1,146,980**	**1,140,063**	**1,160,950**	**1,170,208**	**1,595,163**	**1,554,393**

<u>Explanatory Notes Supporting the Cost Driver Information above:</u>

<u>Distribution Expenses – Maintenance</u>

The decrease in 2008 and increase in 2013 are a result of regular fluctuations in costs year over year. In 2008 the decrease in costs is offset by the increase in tree trimming costs explained below.

Tree Trimming

SLHI performs routine inspections of its system and identifies areas for preventative tree trimming based on the level of risk identified. In 2008 and 2010 the weather was a driver in the increased costs associated with tree trimming. Due to heavy rainfall in July and hot temperatures in August, vegetation growth increased requiring more tree trimming. The 2011 budget for tree trimming was increased to allow for the increased need for tree trimming.

Maintenance of Meters – Smart Meters

The increase in the 2012 Bridge year is due to recognizing on-going expenses relating to the maintenance of smart meters. These costs were previously tracked in Account 1556 – Smart Meters – OM&A. SLHI received a decision from the Board on August 23, 2012 to dispose of Variance accounts 1555 and 1556, therefore these costs will be recorded in the applicable expense accounts going forward.

Distribution Expenses – Operations

The increase in 2008, decrease in 2009 and increase in 2012 are a result of regular fluctuations in costs year over year. In 2010 the costs increased by $62,269. This was driven mainly by the elimination of meter reading for residential and GS < 50 kW customers due to smart meters. As seen below, meter reading expense decreased by $48,629. The balance of the increase is explained by regular fluctuations in costs.

Meter Revarification Costs

In 2008 SLHI spent less on meter revarification due to the impending implementation of smart meters.

Training Costs

The 2008 decrease in training was due to less than budgeted spending for training that year. In 2011 the increase of $26,000 in training was due to training required for outside staff to acquire their AZ Driver's licences along with defensive driving training. The AZ training was required in order for our outside staff to be able to float our large equipment to work sites. Prior to this SLHI was hiring an outside party to perform the task. Given that our service territory is largely rural and the need for equipment in areas not accessible by roads is high, the cost of the training will provide future savings by eliminating the need to hire an external party to perform the work.

Transformer Testing

SLHI's maintenance program requires that transformers be tested on an on-going basis for PCBs and defects. In 2010 SLHI tested all 840 transformers for PCBs in compliance with Ontario Regulation 362. The costs represent internal labour to collect oil samples as well as the costs for PCB testing and disposals. SLHI began the program again in 2012 and will complete in 2013.

Customer Billing/Collecting

The 2008 increase is the result of higher actual spending for Customer billing and collecting costs. The decrease in 2010 was a result of decreased bank services charges by $10,000. The 2012 increase is a result of higher projected bank service charges as well as increased labour costs due to organizational restructuring which is further explained in Exhibit 4, Tab 2, Schedule 4.

Bad Debt Expense

In 2009 bad debt increased as a result of two businesses in the area going out of business, and subsequently leaving the area. SLHI had been working with these accounts for some time in efforts to collect outstanding amounts while still allowing them to remain in operation. The reduction in 2010 is due to the expense level returning to typical levels after 2009. The decrease in 2011 is due to an increase in collections through the year.

Meter Reading Expense

Meter Reading Expense decreased in 2010 by $48,629 due to the implementation of automated meter readings and smart meters. SLHI installed the majority of their smart meters in 2009, and in 2010 transitioned to automated readings for residential and GS < 50 kW customers. Therefore, labour in this category was reduced significantly.

Amounts transferred from Account 1556

As stated earlier, SLHI filed their Smart Meter Final Disposition Application in 2012. The Board approved the application, therefore costs recorded in Account 1556 – Smart Meter OM&A were transferred to the applicable expense accounts in 2012. This is a one-time entry; therefore 2013 shows a decrease for the same amount.

Management/General Admin Salaries/Expenses

The increases in 2009 and 2011 are a result of regular fluctuations in various management and Administration costs year over year.

Regulatory Expenses

The 2009 decrease reflects the decrease in expense due to the preparation of the 2008 Cost of Service Application. SLHI budgeted $25,000 in 2008 for professional fees in conjunction with the 2008 Cost of Service Application. The decrease of $15,221 in 2009 is due to actual lower costs than budgeted.

SLHI budgeted $42,245 in 2012 for professional fees related to the preparation of the 2013 Cost of Service Application, since much of the work will be incurred in 2012. SLHI endeavours to take on as much of the research work in house, however this is a difficult item to budget for as one case matter could potentially be significant. The decrease of $22,933 in 2013 reflects the removal of the one-time costs associated with the preparation of the 2013

Cost of Service Application and taking into consideration the annualized amount of $19,312 proposed to be collected over the four year term.

One Time Costs

The one-time costs are explained in detail in Exhibit 4, Tab 1, Schedule 1.

2010 Audit fees not accrued

SLHI's 2010 external audit fees of $16,808 were not accrued, but recorded in 2011 expenses. Therefore the 2010 audit fees were understated and the 2011 fees were overstated. The auditor felt that the amount was not material and an adjustment was not made.

New Capitalization Policy

As discussed in Exhibit 2, Tab5, SLHI adopted a new capitalization policy in 2012 order to align with IFRS. The change in expense reflects the non-major equipment, burdens and management labour no longer capitalized under the new policy.

Asset Management Plan Consulting fees

An outside consultant was hired to assist in the development of an asset management plan in 2012.

Persisting due to Organizational Restructuring

In 2012 SLHI underwent some organizational restructuring due to the retirement of the President/CEO. These costs represent the additional wages that will persist due to the restructuring and succession planning implementation.

Succession Planning/Implementation

These costs represent the additional wages and consulting fees resulting from the retirement of the President/CEO. These costs are explained further in Exhibit 4, Tab 2, Schedule 4.

Miscellaneous

Changes in miscellaneous expenses represent various year over year changes as described in the account by account variance analysis below.

Variance Analysis by Account

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22 2012, SLHI has provided variance analyses for the 2013 Test Year vs. 2008 Actual (last rebase year) and between the 2013 Test Year and 2011 Actual (Most Current Actual). SLHI has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $50,000. The variances are indicated in the following tables and an explanation of each variance is presented in the following section.

Table 4.30: 2008 Actual to 2013 Test Year - Operations Expenses - Account Variances					
USoA	**Distribution Expenses - Operations**	**2008 Actual**	**2013 Test**	**Variance - $**	**Variance - %**
5005	Operation Supervision and Engineering				
5010	Load Dispatching				
5012	Station Buildings and Fixtures Expense				
5014	Transformer station Equipment - Operation Labour				
5015	Transformer Station Equipment - Operation Supplies and Expenses				
5016	Distribution Station Equipment - Operation Labour				
5017	Distribution Station Equipment - Operation Supplies and Expenses				
5020	Overhead Distribution Lines and Feeders - Operations Labour	343,631	474,385	130,754	38.05%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	55,862	84,010	28,148	50.39%
5030	Overhead Sub-transmission Feeders - Operation				
5035	Overhead Distribution - Transformers - Operation	12,339		-12,339	-100.00%
5040	Underground Distribution Lines and Feeders - Operation Labour				
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses				
5050	Underground Sub-transmission Feeders - Operation				
5055	Underground Distribtuion Transformers - Operation				
5060	Street lIghting and Signal System Expense				
5065	Meter Expense	497		-497	-100.00%
5070	Customer Premises - Operation Labour				
5075	Customer Premises - Operation Materials and Expense				
5085	Miscellaneous Distribution Expense	13,995	69,968	55,973	399.95%
5090	Underground Distribution Lines and Feeders - Rental Paid				
5095	Overhead Distribution Lines and Feeders - Rental Paid				
5096	Other Rent				
	Total Operations	**426,324**	**628,363**	**202,039**	**47.39%**

Table 4.31: 2008 Actual to 2013 Test Year - Maintenance Expenses - Account Variances

USoA	Distribution Expenses - Maintenance	2008 Actual	2013 Test	Variance - $	Variance - %
5105	Maintenance Supervision and Engineering			0	-
5110	Maintenance of Buildings and Fixtures - Distribution Stations			0	-
5112	Maintenance of Tranfromer Station Equipment			0	-
5114	Maintenance of Distribution Station Equipment			0	-
5120	Maintenance of Poles Towers and Fixtures	23,383	48,730	25,347	108.40%
5125	Maintenance of Overhead Conductors and Devices			0	-
5130	Maintenance of Overhead Services			0	-
5135	Overhead Distribution Lines and Feeders - Right of Way	54,678	61,200	6,522	11.93%
5145	Maintenance of Underground Conduit			0	-
5150	Maintenance of Undergroung Conductors and Devices			0	-
5155	Maintenance of Underground Services			0	-
5160	Maintenance of Line Transformers	5,947	13,774	7,827	131.61%
5165	Maintenance of Street Lighting and Signal Systems			0	-
5170	Sentinel Lights - Labour	871	2,000	1,129	129.62%
5172	Sentinel Lights - Materials and Expenses	2,328	2,960	632	27.15%
5175	Maintenance of Meters	3,923	72,941	69,018	1759.32%
5178	Customer Installations Expenses - Leased Property			0	-
5195	Maintenance of Other Installations on Customer Premises				
	Total Maintenance	**91,130**	**201,605**	**110,475**	**121.23%**

Table 4.32: 2008 Actual to 2013 Test Year - Billing and Collecting Expenses - Account Variances

USoA	Billing and Collecting	2008 Actual	2013 Test	Variance - $	Variance - %
5305	Supervision			0	-
5310	Meter Reading Expenses	80,676	4,876	-75,800	-93.96%
5315	Customer Billing	176,648	195,212	18,564	10.51%
5320	Collecting	89,415	96,877	7,462	8.35%
5325	Collecting - Cash Over and Short	-17	0	17	-100.00%
5330	Collection Charges	17		-17	-100.00%
5335	Bad Debt Expense	18,961	20,000	1,039	5.48%
5340	Miscellaneous Customer Accounts Expenses			0	-
	Total Billing and Collecting	**365,700**	**316,965**	**-48,735**	**-13.33%**

Table 4.33: 2008 Actual to 2013 Test Year - Administrative and General Expenses - Account Variances

USoA	Administrative and General	2008 Actual	2013 Test	Variance - $	Variance - %
5605	Executive Salaries and Expenses			0	-
5610	Management Salaries and Expenses			0	-
5615	General Administrative Salaries and Expenses	140,431	244,923	104,492	74.41%
5620	Office Supplies and Expenses	9,152	7,103	-2,049	-22.39%
5625	Administrative Expense Transferred - Credit			0	-
5630	Outside Serives Employed	28,446	36,773	8,327	29.27%
5635	Property Insurance	24,888	18,850	-6,038	-24.26%
5640	Injuries and Damages			0	-
5645	OMERS Pensions and Benefits			0	-
5646	Employee Pensions and OPEB			0	-
5647	Employee Sick Leave			0	-
5650	Franchise Requirements			0	-
5655	Regulatory Expenses	26,595	33,046	6,451	24.26%
5660	General Advertising Expenses	1,080	1,061	-19	-1.76%
5665	Miscellaneous General Expenses	12,920	40,882	27,962	216.42%
5670	Rent	17,969	19,866	1,897	10.56%
5672	Lease Payment Charge			0	-
5675	Maintenance of General Plant			0	-
5680	Electrical Safety Authority Fees	2,345	2,501	156	7%
5681	Special Purpose Charge Expense			0	-
5685	Independent Electricity System Operatior Fees and Penalties			0	-
5695	OM&A Control Account			0	-
					-
	Total Administrative and General	**263,826**	**405,005**	**141,179**	**53.51%**

2008 ACTUAL VERSUS 2013 TEST YEAR

5020 – Overhead Distribution Lines and Feeders - Operations Labour $130,754

This account includes portions of compensation for the all outside staff of SLHI. Amounts are recorded here based on individual weekly time sheets. Prior to 2010 SLHI employed a full time meter reader, whose expenses were recorded in Account 5310 – Meter Reading Expense. In 2010 and beyond, SLHI implemented smart meters along with automated meter readings for Residential and GS < 50 kW customers. Therefore the labour costs associated with account 5310 are now recorded in part to Account 5020 as this position has been reclassified as a Groundsman. This is further explained in Exhibit 4, Tab 2, Schedule 4. The balance of the variance is explained by the addition of an extra full time apprentice lineman as a result of succession planning which is further explained in Exhibit 4, Tab 2, Schedule 4.

5085 – Miscellaneous Distribution Expenses $55,973

This account includes amounts budgeted for an additional training of $20,000 in response to succession planning implementation which is further explained in Exhibit 4, Tab 2, Schedule 4. These costs are expected to be incurred for the next four years. An amount of $31,144 is also included in this account as a result of the change in capitalization policy. This amount is related to costs for building maintenance not directly attributed to capital and therefore expensed.

5175 – Maintenance of Meters $69,018

This account includes costs relating to smart meters such as AMI monitoring and network fees, ODS fees and Service Level Agreements. A breakdown is provided below:

Description of Expenses	$
AMI Monitoring Fees	24,480
Operational Data Store	4,651
Elster Service Level Agreement	13,656
WAN Fees	16,380
Total	**59,167**

The remaining variance is explained by increases in the number of hours the other individuals charge time to this account for meter maintenance and increases in compensation over the five year period.

5310 Meter Reading Expense ($75,800)

As explained above, SLHI implemented smart meters and automated meter readings for the Residential and GS < 50 kW customers. Therefore the labour costs associated with this account has been redistributed to Operations in response to the reclassification of our meter reader to groundsman.

5615 – General Administrative Salaries & Expenses $104,492

Within the USoA account 5615, SLHI has reported the costs for senior management, and the accounting department. Since 2008 SLHI has reclassified the position in the accounting department on two occasions. This is a result of increased knowledge and training associated with obtaining a professional accounting designation over this time period. SLHI believes that retaining knowledgeable skilled employees is essential to the success of the organization. Also, restructuring was required due to the retirement of the President/CEO in 2012. This is further detailed in Exhibit 4, Tab 2, Schedule 4. The remainder is attributable to pay increases for both management and non-union positions, and miscellaneous expenses such as travel reimbursement, conference attendance, offsite training, and human resource related expenses.

2011 ACTUAL VERSUS 2013 TEST YEAR:

Table 4.35: 2011 Actual to 2013 Test Year - Operations Expenses - Account Variances

USoA	Distribution Expenses - Operations	2011 Actual	2013 Test	Variance - $	Variance - %
5005	Operation Supervision and Engineering				
5010	Load Dispatching				
5012	Station Buildings and Fixtures Expense				
5014	Transformer station Equipment - Operation Labour				
5015	Transformer Station Equipment - Operation Supplies and Expenses				
5016	Distribution Station Equipment - Operation Labour				
5017	Distribution Station Equipment - Operation Supplies and Expenses				
5020	Overhead Distribution Lines and Feeders - Operations Labour	399,013	474,385	75,372	18.89%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	38,881	84,010	45,129	116.07%
5030	Overhead Sub-transmission Feeders - Operation				
5035	Overhead Distribution - Transformers - Operation			0	-
5040	Underground Distribution Lines and Feeders - Operation Labour				
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses				
5050	Underground Sub-transmission Feeders - Operation				
5055	Underground Distribtuion Transformers - Operation				
5060	Street lIghting and Signal System Expense				
5065	Meter Expense			0	-
5070	Customer Premises - Operation Labour				
5075	Customer Premises - Operation Materials and Expense				
5085	Miscellaneous Distribution Expense	41,159	69,968	28,809	69.99%
5090	Underground Distribution Lines and Feeders - Rental Paid				
5095	Overhead Distribution Lines and Feeders - Rental Paid				
5096	Other Rent				
	Total Operations	**479,053**	**628,363**	**149,310**	**31.17%**

Table 4.36: 2011 Actual to 2013 Test Year - Maintenance Expenses - Account Variances

USoA	Distribution Expenses - Maintenance	2011 Actual	2013 Test	Variance - $	Variance - %
5105	Maintenance Supervision and Engineering			0	-
5110	Maintenance of Buildings and Fixtures - Distribution Stations			0	-
5112	Maintenance of Tranfromer Station Equipment			0	-
5114	Maintenance of Distribution Station Equipment			0	-
5120	Maintenance of Poles Towers and Fixtures	27,278	48,730	21,452	78.64%
5125	Maintenance of Overhead Conductors and Devices			0	-
5130	Maintenance of Overhead Services			0	-
5135	Overhead Distribution Lines and Feeders - Right of Way	68,170	61,200	-6,970	-10.22%
5145	Maintenance of Underground Conduit			0	-
5150	Maintenance of Undergroung Conductors and Devices			0	-
5155	Maintenance of Underground Services			0	-
5160	Maintenance of Line Transformers	2,114	13,774	11,660	551.56%
5165	Maintenance of Street Lighting and Signal Systems			0	-
5170	Sentinel Lights - Labour	2,156	2,000	-156	-7.24%
5172	Sentinel Lights - Materials and Expenses	2,377	2,960	583	24.53%
5175	Maintenance of Meters	3,958	72,941	68,983	1742.88%
5178	Customer Installations Expenses - Leased Property			0	-
5195	Maintenance of Other Installations on Customer Premises				
	Total Maintenance	**106,053**	**201,605**	**95,552**	**90.10%**

Table 4.37: 2011 Actual to 2013 Test Year - Billing and Collecting Expenses - Account Variances

USoA	Billing and Collecting	2011 Actual	2013 Test	Variance - $	Variance - %
5305	Supervision			0	-
5310	Meter Reading Expenses	5,251	4,876	-375	-7.14%
5315	Customer Billing	160,281	195,212	34,931	21.79%
5320	Collecting	90,179	96,877	6,698	7.43%
5325	Collecting - Cash Over and Short	-146	0	146	-100.00%
5330	Collection Charges			0	-
5335	Bad Debt Expense	9,996	20,000	10,004	100.08%
5340	Miscellaneous Customer Accounts Expenses			0	-
	Total Billing and Collecting	**265,561**	**316,965**	**51,404**	**19.36%**

Table 4.38: 2011 Actual to 2013 Test Year - Administrative and General Expenses - Account Variances

USoA	Administrative and General	2011 Actual	2013 Test	Variance - $	Variance - %
5605	Executive Salaries and Expenses			0	-
5610	Management Salaries and Expenses			0	-
5615	General Administrative Salaries and Expenses	179,236	244,923	65,687	36.65%
5620	Office Supplies and Expenses	8,627	7,103	-1,524	-17.67%
5625	Administrative Expense Transferred - Credit			0	-
5630	Outside Serives Employed	37,652	36,773	-879	-2.33%
5635	Property Insurance	18,470	18,850	380	2.06%
5640	Injuries and Damages			0	-
5645	OMERS Pensions and Benefits			0	-
5646	Employee Pensions and OPEB			0	-
5647	Employee Sick Leave			0	-
5650	Franchise Requirements			0	-
5655	Regulatory Expenses	13,429	33,046	19,617	146.08%
5660	General Advertising Expenses	3,820	1,061	-2,759	-72.23%
5665	Miscellaneous General Expenses	23,166	40,882	17,716	76.47%
5670	Rent	17,969	19,866	1,897	10.56%
5672	Lease Payment Charge			0	-
5675	Maintenance of General Plant			0	-
5680	Electrical Safety Authority Fees	0	2,501	2,501	#DIV/0!
5681	Special Purpose Charge Expense	15,042.0	0.0	-15,042	-100%
5685	Independent Electricity System Operatior Fees and Penalties			0	-
5695	OM&A Control Account			0	-
					-
	Total Administrative and General	**317,411**	**405,005**	**87,594**	**27.60%**

2011 ACTUAL VERSUS 2013 TEST YEAR:

5020 – Overhead Distribution Lines and Feeders – Operations Labour $75,372

In 2012 SLHI hired an additional full time apprentice lineman as a result of succession planning which is further explained in Exhibit 4, Tab 2, Schedule 4.

5175 – Maintenance of Meters $68,983

Please see the explanation provided above for the variance from 2011 actual to 2013 Test Year for this account. SLHI received approval for its 2012 Smart Meter Cost Recovery Application; therefore these costs were recorded in the variance account 1556 in 2011.

The remaining variance is explained by increases in the number of hours the other individuals charge time to this account for meter maintenance and increases in compensation over the five year period.

5615 – General Administrative Salaries & Expenses $65,687

Account 5615 contains the burdened salaries and expenses of executives, the accounting department, and the administrative assistant. Approximately $58,000 of this increase is due to structural reorganization relating to the retirement of the President/CEO in 2012 along with annual increases. The variance is further explained in Exhibit 4, Tab 2, Schedule 4.

Employee Compensation, Pension Expense and Post Retirement Benefits

Compensation/Performance System

Union

SLHI's unionized staff is represented by the Power Workers Union. The current collective agreement expires March 31, 2013 and SLHI will be entering formal negotiations prior to that date. The current agreement, which was entered into in April 2010, includes annual wage increases of 3.0% April 1, 2010, 2.5% April 1, 2011and 2.5% April 1, 2012.

Executive/Management

Executive and Management compensation plan consists of salaries and benefits. Each position within the company has been placed on a pay scale which is reviewed annually by senior management and the Board of Directors' Compensation Committee. Each employee's position within their respective range is reviewed based on performance and an inflationary adjustment. Changes to senior management compensation, if any, are approved by the Board of Directors. SLHI does not offer any incentive or bonus compensation.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, and vacation. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and management employees.

All full time staff participates in the OMERS pension plan.

Employee Compensation and Benefits:

The employee complement, compensation and benefit information is provided in Table 4.40 below. Due to SLHI having only one executive, one management and one non-union employee, SLHI has aggregated the executive, management and non-union together in the union category.

Table 4.40: Employee Compensation

	Last Rebasing Year (2008 Board-Approved)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis							
Number of Employees (FTEs including Part-Time)[1]							
Executive	1	1	1	1	1	1.20	1
Management	1	1	1	1	1	1.00	1
Non-Union						0.42	1
Union	5	6	6	6	6	5.75	6
Total	7	8	8	8	8	8.37	9
Number of Part-Time Employees							
Executive							
Management							
Non-Union							
Union	1						
Total	1	-	-	-	-	-	-
Total Salary and Wages							
Executive							
Management							
Non-Union							
Union	$ 474,644	$ 531,188	$ 589,810	$ 602,342	$ 612,696	$ 703,255	$ 641,205
Total	$ 474,644	$ 531,188	$ 589,810	$ 602,342	$ 612,696	$ 703,255	$ 641,205
Current Benefits							
Executive							
Management							
Non-Union							
Union	$ 35,847	$ 67,911	$ 81,159	$ 82,787	$ 97,995	$ 102,140	$ 98,689
Total	$ 35,847	$ 67,911	$ 81,159	$ 82,787	$ 97,995	$ 102,140	$ 98,689
Accrued Pension and Post-Retirement Benefits							
Executive							
Management							
Non-Union							
Union		$ 84,458	$ 82,964	$ 88,222	$ 82,521	$ 48,240	$ 45,551
Total	$ -	$ 84,458	$ 82,964	$ 88,222	$ 82,521	$ 48,240	$ 45,551
Total Benefits (Current + Accrued)							
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 35,847	$ 152,369	$ 164,123	$ 171,009	$ 180,516	$ 150,380	$ 144,240
Total	$ 35,847	$ 152,369	$ 164,123	$ 171,009	$ 180,516	$ 150,380	$ 144,240
Total Compensation (Salary, Wages, & Benefits)							
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 510,491	$ 683,557	$ 753,933	$ 773,351	$ 793,212	$ 853,635	$ 785,445
Total	$ 510,491	$ 683,557	$ 753,933	$ 773,351	$ 793,212	$ 853,635	$ 785,445
Compensation - Average Yearly Base Wages							
Executive							
Management							
Non-Union							
Union	$ 62,563	$ 66,399	$ 73,726	$ 75,293	$ 76,587	$ 84,021	$ 71,245
Total							
Compensation - Average Yearly Overtime							
Executive							
Management							
Non-Union							
Union							
Total							
Compensation - Average Yearly Incentive Pay							
Executive							
Management							
Non-Union							
Union							
Total							
Compensation - Average Yearly Benefits							
Executive							
Management							
Non-Union							
Union	$ 5,121	$ 8,489	$ 10,145	$ 10,348	$ 12,249	$ 12,203	$ 10,965
Total							
Total Compensation	$ 510,491	$ 683,557	$ 753,933	$ 773,351	$ 793,212	$ 853,635	$ 785,445
Total Compensation Capitalized (CGAAP)		$ 54,788	$ 75,782	$ 73,964	$ 94,913	$ 99,595	
Total Compensation Charged to OM&A (CGAAP)	$ 510,491.00	$ 628,769.00	$ 678,151.00	$ 699,387.00	$ 698,299.00	$ 754,040.00	
Total Compensation Capitalized (MCGAAP)							$ 94,779
Total Compensation Charged to OM&A (MCGAAP)					$ 793,212.00	$ 853,635.00	$ 690,666.00

Change in Employee Compensation & Benefits

2009 Actual vs. 2008 Actual

Union:
Change in FTE: +1
Change in Wages: +58,622

In 2008 SLHI added a Full time lineman. This employee was previously a part-time seasonal employee who worked only in the summer months and became full time on January 31, 2008.

The change in wages is due to the increased wages for the additional full time position along with the 3% inflation increase as per the collective agreement.

2010 Actual vs. 2009 Actual

Union:
Change in FTE: 0
Change in Wages: +12,532

There was an increase of 3% on April 1, 2010 as per collective agreement and progression by some individuals within job classifications and pay grades, as per the collective agreement.

Also, Financial and Regulatory Officer increase of approximately 8% to remain competitive with industry wages and retain key staff members.

2011 Actual vs. 2010 Actual

Union:
Change in FTE: 0
Change in Wages: +$10,354

There was no change in staff in 2011, although the Financial and Regulatory Affairs Officer was promoted to CFO upon completion of the CGA program of professional studies in September 2011. There was also and increase of 2.5% on April 1, 2011 as per the collective agreement.

2012 Bridge vs. 2011 Actual

Union:
Change in FTE: +0.37
Change in Wages: +$90,559

In 2012 SLHI underwent a structural reorganization in response to the retirement of its President/CEO and a succession planning exercise. Also, there was some overlap of approximately 4 months where the current President/CEO and the outgoing President/CEO were still on the payroll due to exhausting holiday time owed to the outgoing President/CEO (+.2). The reorganization involved reclassifying some positions in order to fill gaps in areas left by the outgoing President/CEO. The Line Supervisor was promoted to Operations Manager to fill the technical gap left by the outgoing President/CEO. The current President/CEO has a strong accounting and finance knowledge base, therefore the position of CFO was removed and replaced with an Accounting and Regulatory Clerk position (+.42 in 2012).

In March 2012 one lineman left the company (-1.0), which left a position to be filled. This resulted in a severance package paid to the outgoing employee. At the time, SLHI determined through the succession planning exercise, that they would hire two (2) additional linemen (+.75 in 2012). The current remaining line staff consists of two individuals reaching early retirement age in the next few years. Therefore hiring two apprentices would allow SLHI to train and have in place sufficient qualified staff when the time comes for the retirements within the line staff.

Other changes resulted in the reclassification of the Meter Reader to Groundsman. Smart meters eliminated the need for a full time meter reader in 2009. As a result the position was reclassified as Labourer at that time. Upon review of the duties being performed by the Labourer it was determined that the position should be reclassified as Groundsman.

The change in wages is a result of a combination of, the overlap in wages for the President/CEO, the severance package, the promotion of the Line Supervisor and reclassification, the addition of a FTE and an increase of 2.5% on April 1, 2012 as per the collective agreement.

2013 Test vs. 2012 Bridge

Union:
Change in FTE: +0.63
Change in Wages: -$62,050

The +.63 change in FTE is a result of the reorganization described above in 2012.

The change in wages is a result of the removal of the overlap of wages in 2013for the President/CEO and severance package.

Change in Benefits

In 2011 OMERS released a 3-year plan indicating approximately 1% per year increase in OMERS premiums beginning in 2012. The expected increase for 2013 was confirmed by email to SLHI on July 6, 2012. The following is an excerpt from that email:

> **OMERS 2013 Contribution Rates and Plan Changes Announced**
>
> On June 28, 2012, the OMERS Sponsors Corporation (SC) announced the 2012 Plan changes that were passed – from those that were proposed during the 2012 Specified Plan Changes cycle:
>
> - **A contribution rate increase for both members and employers, beginning in 2013.** (This is the third of the three planned rate increases announced in 2010 as part of OMERS deficit reduction strategy.)
> - **A cap to the amount of contributory earnings that may be included for OMERS pension purposes.**
>
> Although not a Plan change, the SC also approved a new method for allocating contribution rate adjustments in the future, and the SC decided to file the December 31, 2011, actuarial valuations for the OMERS Primary Pension Plan (OMERS Plan) and Supplemental Plan (for police, firefighters and paramedics).
>
> OMERS 2013 Contribution Rates

Contributions to the OMERS Plan are made by members and matched by employers. Along with investment earnings, contributions provide members with lifetime retirement income.

Contribution rate changes are effective with the first full pay in 2013.

Contribution rates for normal retirement age 65 members

- On earnings up to CPP earnings limit*: 2012 is 8.3%; **2013 will be 9.0%**
- On earnings over CPP earnings limit*: 2012 is 12.8%; **2013 will be 14.6%**

Contribution rates for normal retirement age 60 members

- On earnings up to CPP earnings limit*: 2012 is 9.4%; **2013 will be 9.3%**
- On earnings over CPP earnings limit*: 2012 is 13.9%; **2013 will be 15.9%**

*CPP earnings limit (Year's Maximum Pensionable Earnings or YMPE) in 2012 is $50,100; the limit in 2013 will be higher. OMERS members pay a lower rate of contributions on earnings up to the YMPE because OMERS and the CPP are designed to work together to provide pension benefits.

This increase in OMERS pension costs has been included in the cost of current benefits in this application. The increases for 2012 and 2013 are compounded by general salary increases.

Table 4.41: Pension Premium Information

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
OMERS Premiums paid	$36,012	$40,779	$42,407	$50,233	$58,624	$56,507

Post-Retirement Benefits - Liability:

SLHI has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year, in Table 2.31 below.

Post-Retirement Benefits - Premiums:

SLHI pays certain health, dental, and life insurance benefits on behalf of its retired employees. Actual premiums paid for 2009 Actual, 2010 Actual, 2011 Actual, 2011 Actual, 2012 Bridge Year, and 2013 Test Year, are shown in Table 2.31 below.

Table 4.42: Post Retirement Benefit Information

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Premiums & Expenses Paid	$539	$570	$637	$703	$3,909	$8,300
Change in Accrued Liability	$4,853	-$1,494	$5,258	-$5,701	-$46,450	$5,225
Total Post Employment Benefit Expense	**$5,392**	**-$924**	**$5,895**	**-$4,998**	**-$42,541**	**$13,525**

The only post retirement benefit expenses SLHI incurs are the premiums for Group Life insurance from 2008 to 2011. Beginning in 2012, SLHI has additional expenses for health care benefit premiums for one retiree. The change in 2012 is a result of the Retirement bonus paid out.

CHARGES TO AFFILIATES FOR SERVICES PROVIDED

SLHI does not have any Affiliates.

PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES

SLHI purchases some services and products from third parties. Table 4.60 discloses the expenditures by vendor where the annual amount exceeded $50,000 per year, for the years 2008, 2009, 2010 and 2011, respectively.

SLHI's procurement policy is attached as Appendix 4-A. SLHI has followed this policy in the past and will continue to do so in the future.

Table 4.60 contains the historical Non-Affiliate Supplier information including Vendor, total amount of goods or services purchased and the procurement method used.

Table 4.60: Non-Affiliate Suppliers By Year			
2008 Non-Affiliate Suppliers			
Vendor	**Amount**	**Product/Service**	**Procurement Method**
MGM Electric	150,565	Distribution Equipment/Materials	Single Source
OMERS	72,024	Pension Plan	Sole Source
Receiver General for Canada	173,381	Source Deductions	Sole Source
Thunder Bay Hydro Utility Services Inc.	140,962	Billing/Settlement/Collection Services/CDM Program Management	multi-year contract
2009 Non-Affiliate Suppliers			
Vendor	**Amount**	**Product/Service**	**Procurement Method**
Elster Canadian Meter	55,455	Smart Meters	RFP
MGM Electric	163,849	Distribution Equipment/Materials	Single Source
OMERS	81,558	Pension Plan	Sole Source
Receiver General for Canada	255,195	Source Deductions	Sole Source
Thunder Bay Utility Services Inc.	224,553	Billing/Settlement/Collection Services/CDM Program Management/ Smart Meter Implementation Services	multi-year contract
2010 Non-Affiliate Suppliers			
Vendor	**Amount**	**Product/Service**	**Procurement Method**
MGM Electric	244,501	Distribution Equipment/Materials	Single Source
OMERS	84,813	Pension Plan	Sole Source
Receiver General for Canada	335,164	Source Deductions	Sole Source
Thunder Bay Hydro Utility Services Inc.	155,719	Billing/Settlement/Collection Services/CDM Program Management	multi-year contract
2011 Non-Affiliate Suppliers			
Vendor	**Amount**	**Product/Service**	**Procurement Method**
Guelph Utility Pole Company Ltd.	48,697	poles	Sole Source
MGM Electric	119,959	Distribution Equipment/Materials	Single Source
OMERS	100,467	Pension Plan	Sole Source
Receiver General for Canada	435,799	Source Deductions	Sole Source
Thunder Bay Hydro Utility Services	173,122	Billing/Settlement/Collection Services/CDM Program Management	multi-year contract

Depreciation, Amortization and Depletion

Amortization on capital assets is calculated as follows:

- SLHI uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year plus 50% of the current year capital additions.

- SLHI's amortization policy has been to take a full year's amortization on pooled capital additions during the current year. As per OEB guidelines, LDCs are required to use the half-year rule when accounting for amortization expense. For this rate application, SLHI has applied the half year rule for calculating depreciation expense for the years 2007 to 2012 and has provided a reconciliation to its audited financial statements due to the discrepancy caused by the difference in accounting policies. SLHI recognizes that it should have changed its accounting policy to the half year rule following the 2008 cost of service application. However this did not occur. SLHI will change its accounting policy for amortization to reflect the half year rule for 2012.

- Depreciation rates for 2008 to 2012 CGAAP are in line with rates set out in the APH. Depreciation rates for 2012 and 2013 MCGAAP are in line with the Kinectrics Study.

- Refer to MCGAAP – Impact on Depreciation for review of changes implemented for 2012 Bridge Year in Exhibit 4, Tab 4, Schedule 2.

Table 4.70: Summary of Amortization Expense - 2008 to 2013

Account	Description	2008 CGAAP Amortization Expense	2009 CGAAP Amortization Expense	2010 CGAAP Amortization Expense	2011 CGAAP Amortization Expense	2012 - Bridge CGAAP Amortization Expense	2012 - Bridge MCGAAP Amortization Expense	2013 - Test MCGAAP Amortization Expense
1611	Computer Software (Formally known as Account 1925)	$ 850	$ 850	$ 1,003	$ 1,684	$ 39,701	$ 39,701	$ 15,607
1612	Land Rights (Formally known as Account 1906)							
1805	Land							
1808	Buildings	$ 3,675	$ 3,675	$ 3,675	$ 3,675	$ 3,675	$ 3,675	$ 3,675
1810	Leasehold Improvements							
1815	Transformer Station Equipment >50 kV							
1820	Distribution Station Equipment <50 kV							
1825	Storage Battery Equipment							
1830	Poles, Towers & Fixtures	$ 117,477	$ 124,385	$ 132,336	$ 138,939	$ 127,737	$ 54,541	$ 70,114
1835	Overhead Conductors & Devices	$ 43,167	$ 43,167	$ 43,199	$ 43,199	$ 43,700	$ 18,068	$ 18,508
1840	Underground Conduit	$ 6,524	$ 6,628	$ 6,698	$ 6,936	$ 6,702	$ 2,392	$ 2,850
1845	Underground Conductors & Devices	$ 30,823	$ 32,236	$ 33,350	$ 35,508	$ 32,802	$ 16,981	$ 21,847
1850	Line Transformers	$ 58,806	$ 59,070	$ 61,824	$ 64,310	$ 59,823	$ 30,345	$ 37,104
1855	Services (Overhead & Underground)							
1860	Meters	$ 13,566	$ 17,403	$ 19,692	$ 11,880	$ 11,733	$ 11,733	$ 12,035
1860	Meters (Smart Meters)					$ 147,661	$ 147,661	$ 43,222
1905	Land							
1908	Buildings & Fixtures							
1910	Leasehold Improvements							
1915	Office Furniture & Equipment (10 years)	$ 906	$ 1,293	$ 1,266	$ 1,257	$ 1,611	$ 1,611	$ 1,851
1915	Office Furniture & Equipment (5 years)							
1920	Computer Equipment - Hardware							
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 1,324	$ 6,016	$ 5,740	$ 5,732	$ 13,823	$ 13,823	$ 9,830
1920	Computer Equip.-Hardware(Post Mar. 19/07)							
1930	Transportation Equipment(8 years)	$ 42,482	$ 39,068	$ 33,688	$ 8,554	$ 9,482	$ 9,482	$ 19,693
1930	Transportation Equipment(5 years)	$ 11,827	$ 9,062	$ 12,561	$ 6,237	$ 6,237	$ 6,237	$ 6,237
1940	Tools, Shop & Garage Equipment	$ 5,866	$ 6,364	$ 6,300	$ 3,590	$ 7,702	$ 7,702	$ 5,519
1945	Measurement & Testing Equipment	$ 1,306	$ 1,267	$ 1,267	$ 1,198	$ 1,087	$ 1,087	$ 1,643
1950	Power Operated Equipment	$ 5,171	$ 5,241	$ 4,267	$ 3,778	$ 3,852	$ 3,852	$ 14,662
1955	Communications Equipment	$ 3,678	$ 3,894	$ 3,519	$ 1,575	$ 1,534	$ 1,534	$ 1,504
1955	Communication Equipment (Smart Meters)							
1960	Miscellaneous Equipment							
1975	Load Management Controls Utility Premises							
1980	System Supervisor Equipment							
1985	Miscellaneous Fixed Assets	$ 2,328	$ 2,509	$ 2,343	$ 1,531	$ 1,233	$ 1,233	$ 1,491
1995	Contributions & Grants	-$ 24,328	-$ 28,177	-$ 32,688	-$ 35,279	-$ 30,523	-$ 22,161	-$ 31,517
	Work In Progress							
Sub total Amortization Expense		**$ 325,448**	**$ 333,951**	**$ 340,040**	**$ 304,304**	**$ 489,572**	**$ 349,497**	**$ 255,875**
Less: Amortization allocated to other Trial Balance accounts		-$ 72,657	-$ 67,405	-$ 63,945	-$ 26,462	-$ 31,127	-$ 31,127	-$ 50,749
Add: Error in Contribution & Grants Amortization (2010)				$ 4,511				
Less: Adjusment for Account 1556								-$ 24,722
NET AMORTIZATION EXPENSE TO INCOME STATEMENT		**$ 252,791**	**$ 266,546**	**$ 280,606**	**$ 277,842**	**$ 458,445**	**$ 318,370**	**$ 180,404**

The year-over-year fluctuations in amortization expense (as seen above) are natural based on capital additions, disposal of assets, and assets becoming fully depreciated. The $180,603 (CGAAP) and $40,528 (MCGAAP) increase for 2012 over 2011 is mainly due to the inclusion of Smart Meters in SLHI's rate base.

SLHI has provided detailed amortization expense calculations using the OEB's methodology and provided a reconciliation to SLHI's Audited Financial Statement amortization amounts (where applicable) in Tables 4.71 through 4.74 below:

Table 4.71 – Amortization Expense for 2011

Appendix 2-CE
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 2011 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 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)	$ 6,545.00		$ 6,545.00	$ 22,500.00	$ 17,795.00	5.00	20.00%	$ 3,559.00	$ 1,684.00	$ 1,875.00	1
1612	Land Rights (Formally known as Account 1906)			$ -	$ -	$ -			$ -	$ -	$ -	
1805	Land			$ -	$ -	$ -			$ -	$ -	$ -	
1808	Buildings	$ 91,864.00		$ 91,864.00	$ -	$ 91,864.00	25.00	4.00%	$ 3,674.56	$ 3,675.00	-$ 0.44	2
1810	Leasehold Improvements			$ -	$ -	$ -			$ -	$ -	$ -	
1815	Transformer Station Equipment >50 kV			$ -	$ -	$ -			$ -	$ -	$ -	
1820	Distribution Station Equipment <50 kV			$ -	$ -	$ -			$ -	$ -	$ -	
1825	Storage Battery Equipment			$ -	$ -	$ -			$ -	$ -	$ -	
1830	Poles, Towers & Fixtures	$ 3,308,410.00		$ 3,308,410.00	$ 165,064.00	$ 3,390,942.00	25.00	4.00%	$ 135,637.68	$ 138,939.00	-$ 3,301.32	3
1835	Overhead Conductors & Devices	$ 1,079,982.00		$ 1,079,982.00	$ -	$ 1,079,982.00	25.00	4.00%	$ 43,199.28	$ 43,199.00	$ 0.28	4
1840	Underground Conduit	$ 167,448.00		$ 167,448.00	$ 5,944.00	$ 170,420.00	25.00	4.00%	$ 6,816.80	$ 6,936.00	-$ 119.20	5
1845	Underground Conductors & Devices	$ 833,738.00		$ 833,738.00	$ 53,964.00	$ 860,720.00	25.00	4.00%	$ 34,428.80	$ 35,508.00	-$ 1,079.20	6
1850	Line Transformers	$ 1,545,612.00		$ 1,545,612.00	$ 62,129.00	$ 1,576,676.50	25.00	4.00%	$ 63,067.06	$ 64,310.00	-$ 1,242.94	7
1855	Services (Overhead & Underground)			$ -	$ -	$ -			$ -	$ -	$ -	
1860	Meters	$ 447,604.00	$ 150,604.00	$ 297,000.00	$ 6,478.00	$ 300,239.00	25.00	4.00%	$ 12,009.56	$ 11,880.00	$ 129.56	8
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1905	Land			$ -	$ -	$ -			$ -	$ -	$ -	
1908	Buildings & Fixtures			$ -	$ -	$ -			$ -	$ -	$ -	
1910	Leasehold Improvements			$ -	$ -	$ -			$ -	$ -	$ -	
1915	Office Furniture & Equipment (10 years)	$ 13,734.00	$ 4,706.00	$ 9,028.00	$ 3,798.00	$ 10,927.00	10.00	10.00%	$ 1,092.70	$ 1,257.00	-$ 164.30	9
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 39,324.00	$ 15,033.00	$ 24,291.00	$ 2,337.00	$ 25,459.50	5.00	20.00%	$ 5,091.90	$ 5,732.00	-$ 640.10	10
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1930	Transportation Equipment(8 years)	$ 347,546.00	$ 279,116.00	$ 68,430.00	$ -	$ 68,430.00	8.00	12.50%	$ 8,553.75	$ 8,554.00	-$ 0.25	11
1930	Transportation Equipment(5 years)	$ 90,317.00	$ 59,131.00	$ 31,186.00	$ -	$ 31,186.00	5.00	20.00%	$ 6,237.20	$ 6,237.00	$ 0.20	12
1940	Tools, Shop & Garage Equipment	$ 64,775.00	$ 31,307.00	$ 33,468.00	$ 2,436.00	$ 34,686.00	10.00	10.00%	$ 3,468.60	$ 3,590.00	-$ 121.40	13
1945	Measurement & Testing Equipment	$ 12,694.00		$ 12,694.00	$ -	$ 12,694.00	10.00	10.00%	$ 1,269.40	$ 1,198.00	$ 71.40	14
1950	Power Operated Equipment	$ 135,802.00	$ 108,187.00	$ 27,615.00	$ -	$ 27,615.00	8.00	12.50%	$ 3,451.88	$ 3,778.00	-$ 326.13	15
1955	Communications Equipment	$ 37,334.00	$ 23,602.00	$ 13,732.00	$ -	$ 13,732.00	10.00	10.00%	$ 1,373.20	$ 1,575.00	-$ 201.80	16
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -	
1985	Miscellaneous Fixed Assets	$ 26,519.00	$ 12,376.00	$ 14,143.00	$ 1,169.00	$ 14,727.50	10.00	10.00%	$ 1,472.75	$ 1,531.00	-$ 58.25	17
1995	Contributions & Grants	-$ 817,216.00		-$ 817,216.00	-$ 73,975.00	-$ 854,203.50	25.00	4.00%	-$ 34,168.14	-$ 35,279.00	$ 1,110.86	18
etc.				$ -	-$ 8,090.00	-$ 4,045.00			$ -	$ -	$ -	
				$ -	$ -	$ -			$ -	$ -	$ -	
	Total	$ 7,432,032.00	$ 684,062.00	$ 6,747,970.00	$ 243,754.00	$ 6,869,847.00			$ 300,235.98	$ 304,304.00	-$ 4,068.03	

Notes to Explain variances:

1: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions
2: Difference is immaterial
3: Half year rule not applied to financial statements until 2012 (165,064/25 = 6,602.56 * ½ = 3,301.28)
4: Difference is immaterial
5: Half year rule not applied to financial statements until 2012 (5,944/25 = 237.76 * ½ = 118.88)
6: Half year rule not applied to financial statements until 2012 (53,964/25 = 2,158.56 * ½ = 1,079.28)
7: Half year rule not applied to financial statements until 2012 (62,129/25 = 2,485.16 * ½ = 1,242.58)
8: Half year rule not applied to financial statements until 2012 (6,478/25 = 259.12 *1/2 = 129.56)
9: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions
10: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions
11: Difference is immaterial
12: Difference is immaterial
13: Half year rule not applied to financial statements until 2012 (2,436/10 = 243.60 *1/2 = 121.80)
14: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions
15: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

16: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

17: Half year rule not applied to financial statements until 2012 (1,169/10 = 116.9 * ½ = 58.45)

18: Half year rule not applied to financial statements until 2012 (73,975/25 = 2,959 * ½= 1,479.50)

Table 4.72 – Amortization Expense for 2012 Bridge Year (CGAAP)

Appendix 2-CF
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 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 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)	$ 29,045.00	$ 4,250.00	$ 24,795.00	$ 52,240.00	$ 50,915.00	5.00	20.00%	$ 10,183.00	$ 39,701.00	-$ 29,518.00	1
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1805	Land	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1808	Buildings	$ 91,864.00		$ 91,864.00	$ -	$ 91,864.00	25.00	4.00%	$ 3,674.56	$ 3,675.00	-$ 0.44	
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	$ 3,473,474.00		$ 3,473,474.00	$ 133,834.00	$ 3,540,391.00	25.00	4.00%	$ 141,615.64	$ 127,737.00	$ 13,878.64	2
1835	Overhead Conductors & Devices	$ 1,079,982.00		$ 1,079,982.00	$ 25,855.00	$ 1,092,909.50	25.00	4.00%	$ 43,716.38	$ 43,700.00	$ 16.38	3
1840	Underground Conduit	$ 173,392.00		$ 173,392.00	$ 6,200.00	$ 176,492.00	25.00	4.00%	$ 7,059.68	$ 6,702.00	$ 357.68	4
1845	Underground Conductors & Devices	$ 887,702.00		$ 887,702.00	$ 35,823.00	$ 905,613.50	25.00	4.00%	$ 36,224.54	$ 32,802.00	$ 3,422.54	5
1850	Line Transformers	$ 1,607,741.00		$ 1,607,741.00	$ 46,948.00	$ 1,631,215.00	25.00	4.00%	$ 65,248.60	$ 59,823.00	$ 5,425.60	6
1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1860	Meters	$ 454,082.00	$150,604.00	$ 303,478.00	$ 3,890.00	$ 305,423.00	25.00	4.00%	$ 12,216.92	$ 11,733.00	$ 483.92	7
1860	Meters (Smart Meters)	$ -		$ -	$ 647,486.00	$ 323,743.00	15.00	6.67%	$ 21,582.87	$ 147,661.00	-$126,078.13	8
1905	Land	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1910	Leasehold Improvements	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1915	Office Furniture & Equipment (10 years)	$ 17,532.00	$ 4,706.00	$ 12,826.00	$ 6,000.00	$ 15,826.00	10.00	10.00%	$ 1,582.60	$ 1,611.00	-$ 28.40	9
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 41,661.00	$ 15,033.00	$ 26,628.00	$ 28,977.00	$ 41,116.50	5.00	20.00%	$ 8,223.30	$ 13,823.00	-$ 5,599.70	10
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1930	Transportation Equipment(8 years)	$ 347,546.00	$279,116.00	$ 68,430.00	$ 89,116.00	$ 112,988.00	8.00	12.50%	$ 14,123.50	$ 9,482.00	$ 4,641.50	11
1930	Transportation Equipment(5 years)	$ 90,317.00	$ 59,131.00	$ 31,186.00	$ -	$ 31,186.00	5.00	20.00%	$ 6,237.20	$ 6,237.00	$ 0.20	
1940	Tools, Shop & Garage Equipment	$ 67,211.00	$ 37,453.00	$ 29,758.00	$ 22,930.00	$ 41,223.00	10.00	10.00%	$ 4,122.30	$ 7,702.00	-$ 3,579.70	12
1945	Measurement & Testing Equipment	$ 12,694.00		$ 12,694.00	$ -	$ 12,694.00	10.00	10.00%	$ 1,269.40	$ 1,087.00	$ 182.40	13
1950	Power Operated Equipment	$ 135,802.00	$108,187.00	$ 27,615.00	$ 720.00	$ 27,975.00	8.00	12.50%	$ 3,496.88	$ 3,852.00	-$ 355.13	14
1955	Communications Equipment	$ 37,334.00	$ 23,602.00	$ 13,732.00	$ -	$ 13,732.00	10.00	10.00%	$ 1,373.20	$ 1,534.00	-$ 160.80	15
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	$ 27,688.00	$ 13,453.00	$ 14,235.00	$ 2,000.00	$ 15,235.00	10.00	10.00%	$ 1,523.50	$ 1,233.00	$ 290.50	16
1995	Contributions & Grants	-$ 891,191.00		-$ 891,191.00	-$ 92,000.00	-$ 937,191.00	25.00	4.00%	-$ 37,487.64	-$ 30,523.00	-$ 6,964.64	17
etc.				$ -	$ 2,109.00	$ 1,054.50		0.00%	$ -	$ -	$ -	
				$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
	Total	$ 7,683,876.00	$695,535.00	$ 6,988,341.00	$ 1,012,128.00	$ 7,494,405.00			$ 345,986.42	$ 489,572.00	-$143,585.58	

Notes to explain variances:

1: Smart Meter Variance Disposition entry for this account was an addition of 50,740 and depreciation of 23,861. Therefore this amount should not be subject to the half year rule as it is accounted for in the disposition entry. The variance from this is 5,074. The balance is due to the fact that SLHI uses the month of acquisition to determine depreciation for new additions

2: ½ rule was applied retroactively (13,878)

3: ½ rule was applied retroactively (16)

4: ½ rule was applied retroactively (358)

5: ½ rule was applied retroactively (3,423)

6: ½ rule was applied retroactively (5,425)

7: ½ rule was applied retroactively (224)

8: Addition of Smart meter to rate base following Smart Meter Rate Recovery Application (104,611 of depreciation. 643,996 of additions not subject to ½ rule (643,996/15 = 42,933.08 * ½ = 21,467)

9: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

10: Smart Meter Variance Disposition entry for this account was an addition of 20,583 and depreciation of 5,146. The balance is due to the fact that SLHI uses the month of acquisition to determine depreciation for new additions.

11: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

12: ½ rule was applied retroactively (736). Meter Variance Disposition entry for this account was an addition of 12,930 and depreciation of 3,055.

13: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

14: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

15: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions
16: ½ rule was applied retroactively (291)
17: ½ rule was applied retroactively (6,964)

Table 4.73 – Amortization Expense for 2012 Bridge Year (MCGAAP)

Appendix 2-CG

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 2012 MCGAAP

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)	Note to explain variance
1611	Computer Software (Formally known as Account 1925)	$ 24,240.00	$ 52,240.00	3.27	5.00	20.00%	$ 7,412.84	$ 5,224.00	$ 12,636.84	$ 39,701.00	-$ 27,064.16	$ 10,448.00	$ 432.00	$ 17,428.84	1
1612	Land Rights (Formally known as Account 1906)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1805	Land	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1808	Buildings	$ 50,840.00	$ -	14.00	25.00	4.00%	$ 3,631.43	$ -	$ 3,631.43	$ 3,675.00	-$ 43.57	$ -		$ 3,631.43	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	$ 2,287,202.00	$ 103,422.00	34.00	45.00	2.22%	$ 67,270.65	$ 1,149.13	$ 68,419.78	$ 54,541.00	$ 13,878.78	$ 2,298.27		$ 69,568.91	3
1835	Overhead Conductors & Devices	$ 605,093.00	$ 25,855.00	34.00	45.00	2.22%	$ 17,796.85	$ 287.28	$ 18,084.13	$ 18,068.00	$ 16.13	$ 574.56		$ 18,371.41	4
1840	Underground Conduit	$ 105,284.00	$ 5,000.00	39.00	50.00	2.00%	$ 2,699.59	$ 50.00	$ 2,749.59	$ 2,392.00	$ 357.59	$ 100.00		$ 2,799.59	5
1845	Underground Conductors & Devices	$ 582,212.00	$ 26,248.00	29.00	40.00	2.50%	$ 20,076.28	$ 328.10	$ 20,404.38	$ 16,981.00	$ 3,423.38	$ 656.20		$ 20,732.48	6
1850	Line Transformers	$ 1,020,305.00	$ 46,948.00	29.00	40.00	2.50%	$ 35,182.93	$ 586.85	$ 35,769.78	$ 30,345.00	$ 5,424.78	$ 1,173.70		$ 36,356.63	7
1855	Services (Overhead & Underground)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1860	Meters	$ 327,572.00	$ 3,890.00	14.00	25.00	4.00%	$ 23,398.00	$ 77.80	$ 23,475.80	$ 11,733.00	$ 11,742.80	$ 155.60	$ 11,778.00	$ 11,775.60	8
1860	Meters (Smart Meters)	$ -	$ 647,486.00	12.00	15.00	6.67%	$ -	$ 21,582.87	$ 21,582.87	$ 147,661.00	-$ 126,078.13	$ 43,165.73		$ 43,165.73	9
1905	Land	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1908	Buildings & Fixtures	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1915	Office Furniture & Equipment (10 years)	$ 9,103.00	$ 6,000.00	7.79	10.00	10.00%	$ 1,168.55	$ 300.00	$ 1,468.55	$ 1,611.00	-$ 142.45	$ 600.00	$ 10.30	$ 1,758.25	10
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1920	Computer Equipment - Hardware	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 12,678.00	$ 28,977.00	2.83	5.00	20.00%	$ 4,479.86	$ 2,897.70	$ 7,377.56	$ 13,823.00	-$ 6,445.44	$ 5,795.40	$ 175.29	$ 10,099.97	11
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
1930	Transportation Equipment(8 years)	$ 34,927.42	$ 89,116.00	4.10	8.00	12.50%	$ 8,518.88	$ 928.29	$ 9,447.17	$ 9,482.00	-$ 34.83	$ 11,139.50		$ 19,658.38	12
1930	Transportation Equipment(5 years)	$ 18,189.09	$ -	3.00	5.00	20.00%	$ 6,063.03	$ -	$ 6,063.03	$ 6,237.00	-$ 173.97	$ -		$ 6,063.03	13
1940	Tools, Shop & Garage Equipment	$ 15,953.00	$ 22,930.00	6.17	10.00	10.00%	$ 2,585.58	$ 1,146.50	$ 3,732.08	$ 7,702.00	-$ 3,969.92	$ 2,293.00	$ 614.62	$ 4,263.96	14
1945	Measurement & Testing Equipment	$ 3,220.00	$ -	2.69	10.00	10.00%	$ 1,197.03	$ -	$ 1,197.03	$ 1,087.00	$ 110.03	$ -	$ 143.53	$ 1,053.50	15
1950	Power Operated Equipment	$ 22,689.00	$ 720.00	5.87	8.00	12.50%	$ 3,865.25	$ 45.00	$ 3,910.25	$ 3,852.00	$ 58.25	$ 90.00		$ 3,955.25	16
1955	Communications Equipment	$ 6,980.00	$ -	4.55	10.00	10.00%	$ 1,534.07	$ -	$ 1,534.07	$ 1,534.00	$ 0.07	$ -	$ 29.78	$ 1,504.29	17
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	$ 6,711.00	$ 2,000.00	5.37	10.00	10.00%	$ 1,249.72	$ 100.00	$ 1,349.72	$ 1,233.00	$ 116.72	$ 200.00	$ 232.54	$ 1,217.18	18
1995	Contributions & Grants	-$ 681,468.00	-$ 92,000.00	29.00	40.00	2.50%	-$ 23,498.90	-$ 1,150.00	-$ 24,648.90	-$ 22,161.00	-$ 2,487.90	-$ 2,300.00		-$ 25,798.90	19
etc.						0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
						0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
	Total	$ 4,451,730.51	$ 968,832.00				$ 184,631.63	$ 33,553.52	$ 218,185.15	$ 349,497.00	-$ 131,311.85	$ 76,389.96	$ 13,416.06	$ 247,605.52	

<u>Notes to explain variances:</u>

1: Smart Meter Variance Disposition entry for this account was an addition of 50,740 and depreciation of 23,861. Therefore this amount should not be subject to the half year rule as it is accounted for in the disposition entry. The variance from this is 5,074. The balance is due to the fact that SLHI uses the month of acquisition to determine depreciation for new additions

2: Difference is immaterial

3: ½ rule was applied retroactively (13,878)

4: ½ rule was applied retroactively (16)

5: ½ rule was applied retroactively (358)

6: ½ rule was applied retroactively (3,423)

7: ½ rule was applied retroactively (5,425)

8: ½ rule was applied retroactively (224), plus fully depreciated asset removal (11,778), Balance immaterial

9: Addition of Smart meter to rate base following Smart Meter Rate Recovery Application (104,611 of depreciation. 643,996 of additions not subject to ½ rule (643,996/15 = 42,933.08 * ½ = 21,467)

10: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

11: Smart Meter Variance Disposition entry for this account was an addition of 20,583 and depreciation of 5,146. The balance is due to the fact that SLHI uses the month of acquisition to determine depreciation for new additions.

12: Difference is immaterial. Due to rounding of estimated useful life.

13: Difference is immaterial. Due to rounding of estimated useful life.

14: ½ rule was applied retroactively (736). Meter Variance Disposition entry for this account was an addition of 12,930 and depreciation of 3,055. Balance due to rounding of estimated useful life.

15: Difference is immaterial. Due to rounding of estimated useful life.

16: Difference is immaterial. Due to rounding of estimated useful life.

17: Difference is immaterial

18: ½ rule was applied retroactively (291). Balance due to rounding of estimated useful life.

19: ½ rule was applied retroactively (6,964). Balance due to rounding of estimated useful life.

Table 4.74 – Amortization Expense for 2013 Test Year (MCGAAP)

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	
					-$ 1,491.00			
	Total Depreciation expense to be included in the test year revenue requirement				**$ 253,988.58**			

Notes to explain variances:

1: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions.

2: Difference is immaterial

3: Difference is immaterial

4: Difference is immaterial

5: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

6: Difference is immaterial and for easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

7: Difference is immaterial and for easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

8: Result of a small calculation error relating to assets that were fully depreciated in 2012. SLHI feels that the difference is immaterial

9: Difference is immaterial and for easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions

10: For easily identifiable assets, SLHI uses the month of acquisition to determine depreciation for new additions. The 86,000 addition is planned for January 2013 therefore the full year amortization was used instead of the half year (86, 000/8 = 10,750 * ½ = 5,375)

11: Difference is immaterial

12: Contribution and Grants uses different amortization period based on what type of asset the contribution is being received for.

Asset Retirement Obligations

SLHI’s only Asset Retirement Obligations (“ARO”) would be related to PCB’s subject to removal from transformers. SLHI conducted transformer testing on all of its transformers in 2010. The legislated requirement is to remove PCB’s greater than 50 ppm. The testing resulted in 8 transformers with PCB’s greater than 50 ppm. SLHI disposed of these transformers at that time, and the costs were not material. SLHI purchases only non-PCB transformers and therefore does not anticipate a further obligation.

INCOME TAX, LARGE CORPORATION TAX

Tax Calculations

Table 4.3-1 below provides a summary of 2008 Approved, the 2008, 2009, 2010, 2011 Actual, included in audited statements, and the 2012 Bridge Year (CGAAP) and 2013 Test Year (MCGAAP) income tax estimate using rates prescribed by the OEB in SLHI's 2011 IRM rate decision and order. A copy of SLHI's most recent (2011) annual federal and provincial tax return has been provided as Appendix 4-B to this exhibit. Copies of SLHI's notices of assessments are provided in Appendix 4-C. In accordance with the June 2012 filing requirements the Board's PILs model has also been completed and submitted and is consistent with the PILs included in the 2013 revenue requirement.

Table 4.3-1: Summary of Income & Captial Taxes 2008 to 2013 Test

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year (CGAAP)	2013 Test Year (MCGAAP)
Income Taxes - Current	46,320	25,818	69,738	47,850	32,740	31,662	9,350
Add: Prior Period Adjustments			2,480				
Total Taxes	**46,320**	**25,818**	**72,218**	**47,850**	**32,740**	**31,662**	**9,350**

SLHI's detailed tax calculations using the most recent tax rates are provided in Table 4.3-2.

Table4.3-2 – Detailed Tax Calculations for 2008 to 2013

Table 4.3-2: Detailed Tax Calculations 2008 to 2012 Bridge CGAAP , 2013 Test (MCGAAP)						
Item	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2012 Bridge**	**2013 Test**
Accounting Net Income Before Taxes	**120,839**	**128,815**	**309,310**	**337,899**	**112,604**	**222,769**
Additions:						
Interest and penalties on taxes			2,314	169		
Amortization of tangible assets	325,447	333,914	344,552	304,302	489,572	255,875
Non-deductible meals and entertainment expense	950	1,503	1,463	1,283	1,250	1,250
Loss on disposal of assets	2,001	16,347				
Loss on impairment of Goodwill		300,979				
Other Additions	6,939	41,799	78,270	8,329		
Deductions:						
Capital Cost Allowance from Schedule 8	269,264	322,806	352,167	358,654	391,414	412,370
Cumulative Eligible Capital Deduction from Schedule 10	10,349	9,624	8,950	8,324	7,741	7,199
Other Deductions	337	2,686	633	32,954		
Total Tax Adjustments to Accounting Income	55,387	359,426	64,849	-85,849	91,667	-162,444
Income for Tax Purposes	**176,226**	**488,241**	**374,159**	**252,050**	**204,271**	**60,325**
Effective Tax Rate Reflecting Tax Credits (Federal & Provincial)	15.50%	16.50%	16.00%	15.50%	15.50%	15.50%
Income Taxes before Credits	**27,315**	**80,560**	**59,865**	**39,068**	**31,662**	**9,350**
Less: Apprenticeship Training Tax Credit	1,511	10,822	12,000	6,329	0	
Income Taxes	**25,804**	**69,738**	**47,865**	**32,739**	**31,662**	**9,350**
Captial Tax Calculation						
Total Rate Base	5,621,632	5,292,553	5,500,938	5,591,540	5,847,996	6,066,323
Reduction	-15,000,000	-15,000,000	-15,000,000			
Rate	0.225%	0.225%	0.150%	0.000%	0.000%	0.000%
Captial Tax - as calculated	-	-	-	-	-	-
Capital Tax - As per Audited Financial Statements	-	-	-	-	-	-

Tax Credit Calculations

SLHI will be eligible for the Apprenticeship Tax Credits in the 2013 Test Year. These credits have been calculated based on the current rules dictated by Canada Revenue Agency. The 2013 Test Year credits have been annualized based on the projected credits for 2013-2016. Table 4.3-3 below detail how the Apprenticeship Tax Credits have been calculated.

Table 4.3-3: Apprenticeship Tax Credit Calculation 2013

2013 Apprentices	**Max Tax Credit**
Apprentice #1	10,000
Apprentice #2	10,000
	20,000
2014 Apprenticeships	20,000
2015 Apprenticeships	20,000
2016 Apprenticeships	20,000
Total	**80,000**
Annualized	**20,000**

Table 4.3-2 above does not include these tax credits as they would provide a negative tax payable. Should the actual tax calculation provide a negative tax payable, SLHI plans to carry the credit forward in order to reduce future taxes payable. The amount of taxes calculated in the 2013 test year without the credit is immaterial, and therefore was not changed.

CAPITAL COST ALLOWANCE (CCA)

SLHI is providing Capital Cost Allowance continuity schedules for the 2012 Bridge Year (Tables 4.3-5 & 4.3-6) and the 2013 Test Year (Tables 4.3-7 & 4.3-8) as follows:

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

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	3,880,847	0	0	3,880,847	0	0	3,880,847	0	3,880,847	4%	155,234	3,725,613
2	Distribution System - pre 1988		0	0	0	0	0	0	0	0	6%	0	0
6	Buildings - after 1990		0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	33,544	0	0	33,544	29,650	1,295	61,899	14,825	47,074	20%	9,415	52,484
10	Computer Hardware/ Vehicles	60,684	0	0	60,684	118,093	1,753	177,024	59,047	117,978	30%	35,393	141,631
10.1	Certain Automobiles		0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	11,250	0	0	11,250	52,240	0	63,490	26,120	37,370	100%	37,370	26,120
3	Buildings - pre 1990		0	0	0	0	0	0	0	0	5%	0	0
			0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3		0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4		0	0	0	0	0	0	0	0		0	0
14	Franchise		0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	81	0	0	81	0	0	81	0	81	45%	36	45
50	Computers & Systems Hardware acq'd post Mar 19/07	5,021	0	0	5,021	0	0	5,021	0	5,021	55%	2,762	2,259
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	1,779,493			1,779,493	810,036	294,462	2,295,067	405,018	1,890,049	8%	151,204	2,143,863
	SUB-TOTAL - UCC	**5,770,920**	**0**	**0**	**5,770,920**	**1,010,019**	**297,510**	**6,483,429**	**505,009**	**5,978,419**		**391,414**	**6,092,015**
CEC	Goodwill		0	0	0								
CEC	Land Rights		0	0	0								
CEC	FMV Bump-up		0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

1 **Table 4.3-6 – 2012 CEC Continuity Schedule**

Cumulative Eligible Capital					**110,590**
Additions					
Cost of Eligible Capital Property Acquired during Test Year					
Other Adjustments	0				
Subtotal	0	**x 3/4 =**	0		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0		
			0		**0**
Amount transferred on amalgamation or wind-up of subsidiary	0				**0**
Subtotal					**110,590**
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year					
Other Adjustments	0				
Subtotal	0	**x 3/4 =**			**0**
Cumulative Eligible Capital Balance					**110,590**
Current Year Deduction			**110,590**	**x 7% =**	**7,741**
Cumulative Eligible Capital - Closing Balance					**102,849**

Table 4.3-7 – 2013 CCA / UCC Continuity Schedule

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 3,725,613			$ 3,725,613	$ -	$ 3,725,613	4%	$ 149,025	$ 3,576,589
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 52,355	98,000		$ 150,355	$ 49,000	$ 101,355	20%	$ 20,271	$ 130,084
10	Computer Hardware/ Vehicles	$ 141,368	2,000		$ 143,368	$ 1,000	$ 142,368	30%	$ 42,710	$ 100,657
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 26,120	1,000		$ 27,120	$ 500	$ 26,620	100%	$ 26,620	$ 500
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 Tha	$ -			$ -	$ -	$ -	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	$ 45			$ 45	$ -	$ 45	45%	$ 20	$ 25
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 2,092,545	126,940		$ 2,219,485	$ 63,470	$ 2,156,015	8%	$ 172,481	$ 2,047,004
50	Data Network Infrastructure Equipment - post Mar 2007	$ 2,259			$ 2,259	$ -	$ 2,259	55%	$ 1,243	$ 1,017
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 6,040,305	$ 227,940	$ -	$ 6,268,245	$ 113,970	$ 6,154,275		$ 412,370	$ 5,855,875

1 **Table 4.3-8 - 2013 CEC Continuity Schedule**

Cumulative Eligible Capital				**102,849**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**102,849**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**102,849**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**102,849**	**x 7% =**	**7,199**
Cumulative Eligible Capital - Closing Balance				**95,649**

MODIFIED CGAAP

MCGAAP – Impact on OM&A

Conversion to MCGAAP

SLHI has amended the accounting policies used for 2012 and 2013 to be more in line with Modified International Reporting Standards (MIFRS).

International Accounting Standard 16 (IAS 16) – Property, Plant and Equipment (PP&E), states the cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where Canadian GAAP allowed for the capitalization of general and administrative overhead, MIFRS does not.

In order to allocate costs between operating expenses and capital expenses, SLHI utilizes the following burdens:

Payroll
Fleet maintenance
Stores

In reviewing each of these burdens SLHI has identified the following expenses that are not appropriate to capitalize under MIFRS.

Payroll

The payroll burden has included the full costs of all employees including, wages, and benefits. Of these costs $2,988 was determined to not be appropriate for capitalization under MIFRS. These costs relate to Management costs allocated on a percentage basis. The balance of these burdens was determined to be appropriately allocated through timesheets and therefore no change was required.

Fleet Maintenance

Through the Fleet burden, the total cost of operating all vehicles is charged to capital based on the percentage of total labour costs associated with capital projects for the year from timesheets. However, included in the Fleet expense are miscellaneous expenses of $3,905 that are not considered to be directly attributed to capital under MIFRS will be expensed instead of capitalized.

Stores

Included in this burden are purchasing expenses, building and property charges. The purchasing activities are directly attributable to the materials used in capital projects and therefore will continue to be capitalized as part of the Stores burden. The cost of the building and property expenses are allocated to capital based on the percentage of labour costs associated with capital projects for the year from timesheets. SLHI reviewed the actual costs in 2011 and determined the difference in directly allocating the costs as opposed to a percentage allocation was an additional expense of $2,969. For 2012 the estimated impact is $5,354 of additional expense.

Table 4.4-1: Impact of MCGAAP on Burdens and OM&A

Burdens	General Administration and Labour	Labour Burden	Property Charge	Miscellaneous	Total
Payroll Burden		2,988			2,988
Fleet Burden				3,905	3,905
Stores Burden			5,354		5,354
Total	**0**	**2,988**	**5,354**	**3,905**	**12,247**
Burden Amounts Reallocated to OM&A	**2012 Bridge Year (CGAAP)**	**Amounts Removed from Burdens above and expensed in OM&A**			**2012 Bridge Year (MCGAAP)**
Operations	539,851		5,354	3,905	549,110
Maintenance	320,616				320,616
Billing & Collecting	298,102				298,102
Administration	386,919	2,988			389,907
Total	**1,545,488**				**1,557,735**

MCGAAP – IMPACT ON DEPRECIATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of assets' useful lives, depreciation methods and residual values on an annual basis.

The Board commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to International Financial Reporting Standards, (EB-2009-0408) the Board stated:

> "While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the service lives for their particular assets for financial reporting and regulatory requirements."

SLHI has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinectrics (Kinectrics Report). Table 4.4-2 contains the useful lives by Uniform System of Account, compared to the current useful lives used under CGAAP. Overall, the useful lives have been extended causing depreciation to be reduced in the 2012 Bridge year by $140,175 ($489,572 under CGAAP to $349,497 under MCGAAP).

Table 4.4-2: MCGAAP Amortization Periods & Amortization Expense for 2012

OEB	Description	CGAAP Amortization Period	TUL/Useful Life Range per Kinetrics Report			MCGAAP Amortization Period	2012 MCGAAP Amortization of USoA	Explanation of Difference in Service Life from TUL
			Min UL	TUL	Max UL			
1805	**Land**	N/A		N/A		N/A		
1806	**Land Rights**	N/A		N/A		N/A		
1808	**Buildings**	25		N/I		25	3,675	
1830	**Poles, Towers, Fixtures**	25				45	54,541	
	Wood Poles		35	45	75			
1835	**Overhead conductors & devices**	25				45	18,068	
	Switches		30	45	55			
	Overhead Conductors		50	60	75			
1840	**Underground Conduit**	25				50	2,392	
	Conduits		30	50	85			
1845	**Underground Conductors and Devices**	25				40	16,981	
	Primary cables in Duct		35	40	55			
	Primary cables in Direct Buried		25	30	35			
	Secondary Cables Direct Buried		25	35	40			
	Secondary Cables in Duct		35	40	60			
1850	**Line Transformers**	25	30	40	60	40	30,345	
1850	**Transformer ARO**							
1860	**Meters**	25						
	Smart Meters, Repeaters, Data Collectors			5~20		15	147,661	Includes amortization from disposal of Smart
	Industrial/Current & Potential Transformer			25~50		25	11,733	
1915	**Office Furniture & Equipment**	10		5~15		10	1,611	
1920	**Computer Equipment - Hardware**	5		3~5		5	13,823	Includes amortization from disposal of Smart
1925	**Computer Software**	5		2~5		5	39,701	Includes amortization from disposal of Smart
1930	**Transportation Equipment**						15,719	
	Trucks & Buckets	8~10		5~15		5~8		
	Trailers	10		5~20		10		
	Vans/Cars			5~10		N/A		
1940	**Tools, Shop and Garage Equipment**	10		5~10		10	7,702	
1945	**Measuring & Testing Equipment**	10		5~10		10	1,087	
1950	**Power Operated Equipment**	10		5~10		10	3,852	
1955	**Communication Equipment**	10		2~10		10	1,534	
1985	**Miscellaneous Fixed Assets**	10		5~10		10	1,233	
1995	**Contributions and Grants**	25		Based on asset		40-50	-22,161	
	Subtotal Amortization expense						**349,497**	
	Less: Amortization allocation to other trial balance accounts and overheads						-24,890	
	Net Amortization expense to income statement						**324,607**	
N/A	Not Applicable							
N/I	Not indicated in Kinectrics Study							

Review of Opening Assets Remaining Service Lives

SLHI reviewed all of its existing assets as of December 31, 2011 in anticipation of adoption of IFRS for 2013. All existing infrastructure assets were reviewed to determine type of equipment existing and estimated changes to useful lives.

MCGAAP – IMPACT ON TAX CALCULATIONS

Tax Calculations

Table 4.43 below provides a summary of 2009 Approved, 2009, 2010, and 2011 Actual income taxes included in audited statements, and the 2012 Bridge Year (MCGAAP) and 2013 Test Year (MCGAAP) income tax estimates using rates prescribed by the OEB in SLHI's 2012 IRM rate decision and order. A copy of SLHI's most recent (2011) annual federal and provincial tax return has been provided as Appendix 4-B to this exhibit.

Table 4.43: Summary Income Tax 2008 to 2011 CGAAP and 2012 to 2013 MCGAAP

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Income Taxes - Current	46,320	25,818	69,738	47,850	32,740	10,118	9,350
Add: Prior Period Adjustments			2,480				
Total Taxes	**46,320**	**25,818**	**72,218**	**47,850**	**32,740**	**10,118**	**9,350**

SLHI has provided the Capital Cost Allowance continuity schedules for the 2012 Bridge Year (MCGAAP) under Tables 4.44 & 4.45, and the 2013 Test Year (MCGGAP) under Tables 4.46 & 4.47.

Table 4.44 – CCA Continuity Schedule 2012 (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

Table 4.45 – CEC Continuity Schedule 2012 (MCGAAP)

Cumulative Eligible Capital				**110,590**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**110,590**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**110,590**
Current Year Deduction		**110,590**	**x 7% =**	**7,741**
Cumulative Eligible Capital - Closing Balance				**102,849**

Table 4.46 – CCA Continuity Schedule 2013 (MCGAAP)

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 3,725,613			$ 3,725,613	$ -	$ 3,725,613	4%	$ 149,025	$ 3,576,589
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 52,355	98,000		$ 150,355	$ 49,000	$ 101,355	20%	$ 20,271	$ 130,084
10	Computer Hardware/ Vehicles	$ 141,368	2,000		$ 143,368	$ 1,000	$ 142,368	30%	$ 42,710	$ 100,657
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 26,120	1,000		$ 27,120	$ 500	$ 26,620	100%	$ 26,620	$ 500
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 Tha	$ -			$ -	$ -	$ -	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	$ 45			$ 45	$ -	$ 45	45%	$ 20	$ 25
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 2,092,545	126,940		$ 2,219,485	$ 63,470	$ 2,156,015	8%	$ 172,481	$ 2,047,004
50	Data Network Infrastructure Equipment - post Mar 2007	$ 2,259			$ 2,259	$ -	$ 2,259	55%	$ 1,243	$ 1,017
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 6,040,305	$ 227,940	$ -	$ 6,268,245	$ 113,970	$ 6,154,275		$ 412,370	$ 5,855,875

Table 4.47 – CEC Continuity Schedule 2013 (MCGAAP)

Cumulative Eligible Capital Calculation				
Cumulative Eligible Capital				110,590
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	110,590
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				110,590
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	110,590
Cumulative Eligible Capital Balance				110,590
CEC Deduction	7%			7,741
Cumulative Eligible Capital - Closing Balance				102,849

SLHI has provided detailed income tax calculations using MCGAAP net income, MCGAAP amortization & MCGAAP CCA as shown in Table 4.48 below.

Table 4.48: Detailed Tax Calculations 2012 Bridge (MCGAAP) , and 2013 Test (MCGAAP)

Item	**2012 Bridge**	**2013 Test**
Accounting Net Income Before Taxes	**124,210**	**222,769**
Additions:		
Interest and penalties on taxes		
Amortization of tangible assets	349,496	255,875
Non-deductible meals and entertainment expense	1,250	1,250
Loss on disposal of assets		
Non-deductible penalties		
Loss on impairment of Goodwill		
Other Additions		
Deductions:		
Capital Cost Allowance from Schedule 8	401,937	412,370
Cumulative Eligible Capital Deduction from Schedule 10	7,741	7,199
Other Deductions		
Total Tax Adjustments to Accounting Income	-58,932	-162,444
Income for Tax Purposes	**65,278**	**60,325**
Effective Tax Rate Reflecting Tax Credits (Federal & Provincial)	15.50%	15.50%
Income Taxes before Credits	**10,118**	**9,350**
Less: Apprenticeship Training Tax Credit		
Income Taxes	**10,118**	**9,350**
Captial Tax Calculation		
Total Rate Base	5,875,333	6,106,606
Reduction		
Rate	0.000%	0.000%
Captial Tax - as calculated	-	-
Capital Tax - As per Audited Financial Statements	-	-

CONSERVATION AND DEMAND MANAGEMENT ("CDM") COSTS

SLHI does not request approval to recover of historical Lost Revenue Adjustment Mechanism ("LRAM") amounts related to Conservation and Demand Management (CDM) activities in 2011 at this time. The LRAM amounts calculated using the OPA Final CDM Results for 2011 multiplied by the applicable Board-approved volumetric distribution charge for the year in which the programs occurred resulted in a rate rider of less than 0.0001, and therefore does not exceed the preset disposition threshold. The debit balance of $1,252 has been included in Account 1568 of the Deferral and Variance Account file for disposition at a future rate hearing due to immateriality. Tables 4.51, 4.52 and 4.53 provide the LRAM calculations.

LRAM AMOUNTS

The LRAM adjusts for volumetric variances between actual CDM results and the corresponding quantities used in rate setting. The requested LTAM amounts are derived from savings composed of Ontario Power Authority ("OPA") programs implemented in 2011. The lost revenues are calculated from the year of introduction through to April 30, 2013. SLHI has used the most recent input assumptions in calculating the LRAM Amount. The 2011 OPA Final Evaluation Report has been used in support of the LRAM calculations. A Copy of the 2011 OPA Final Evaluation Report has been included as Appendix 4-D and has also been submitted in Excel format as part of this application.

None of the load reductions were factored into the load forecast underpinning the 2011 or 2012 rates. The calculation of the load reduction is based on the energy and demand savings and the lifespan of the technology by rate class. The reduction in demand related to these programs has been incorporated into the rate forecast for May 1, 2013 and onward. However, energy savings related to OPA Programs delivered in 2011 and 2012 have not been captured.

Table 4.51: Cumulative Net Energy and Demand Savings by Rate Class through April 30 2013 from CDM Programs

Funding Source	Program	Program Year	Residential (kWh)	GS < 50 kW (kWh)	GS 50 to 4,999 kW (kW)
OPA	Appliance Retirement	2011	13,344		
		Persistance in 2012	13,344		
	Applicance Exchange	2011	113		
		Persistance in 2012	113		
	HVAC Incentives	2011	1,408		
		Persistance in 2012	1,408		
	Conservation and Instant Coupon Booklet	2011	15,771		
		Persistance in 2012	15,771		
	Bi-Annual Retailer Event	2011	24,700		
		Persistance in 2012	24,700		
	Efficiency: Equipment Replacement	2011		0	
		Persistance in 2012		0	
	Direct Install Lighting	2011		5,986	2
		Persistance in 2012		5,986	2
	High Performance New Construction	2011	174		
		Persistance in 2012	174		
Total Savings			**111,020**	**11,972**	**4**

Note: The source of the data in the Table above is obtained from the OPA Final CDM Results for 2011.

Table: 4.52: Summary of LRAM Claim by Program and Rate Class

Funding Source	Program	Program Year	Residential	GS < 50 kW	GS 50 to 4,999 kW	LRAM
OPA	Appliance Retirement	2011	$137			$137
		Persistance in 2012	$139			$139
	Applicance Exchange	2011	$1			$1
		Persistance in 2012	$1			$1
	HVAC Incentives	2011	$15			$15
		Persistance in 2012	$15			$15
	Conservation and Instant Coupon Booklet	2011	$162			$162
		Persistance in 2012	$164			$164
	Bi-Annual Retailer Event	2011	$254			$254
		Persistance in 2012	$257			$257
	Efficiency: Equipment Replacement	2011		$0		$0
		Persistance in 2012		$0		$0
	Direct Install Lighting	2011		$48	$3	$51
		Persistance in 2012		$49	$3	$52
	High Performance New Construction	2011	$2			$2
		Persistance in 2012	$2			$2
Total Savings			**$1,149**	**$98**	**$6**	**$1,252**

Note: The dollar values were calculated by using the kWh/kW in Table 4.51 and multiplying the volume by the applicable Board-approved volumetric distribution charge for the year in which the programs occurred.

Table 4.53: LRAM Amounts and Rate Riders by Class						
	LRAM	**Carrying Charges**	**Total**	**Unit**	**2013 Forecasted Billed kWh/Kw**	**Proposed Rate Rider**
Residential	$1,149	$17	$1,166	kWh	34980266	0.0000
General Service < 50 kW	$98	$1	$99	kWh	12526981	0.0000
General Service 50 to 4,999 kW	$6	$0	$6	kW	25251296	0.0000
Total	**$1,252**	**$18**	**$1,271**			

Since SLHI's CDM Programs are all OPA-approved programs that are included in the 2011 OPA Final Evaluation Report found in Appendix 4-D, which has been reviewed by a third-party, SLHI believes this to be sufficient review and verification of the LRAM calculations and is not providing a second third-party report in this Application. SLHI will not be requesting to dispose of the balance of $1,252 due to immateriality.

APPENDIX 4-A

SIOUX LOOKOUT HYDRO PURCHASING POLICY

06 PURCHASING

IT IS THE POLICY OF SIOUX LOOKOUT HYDRO INC. TO MAKE ALL PURCHASES FROM THE SUPPLIER PROVIDING THE LOWEST COST FOR THE REQUIRED QUALITY AS APPROVED BY THE PRESIDENT/CEO

6.1 Where possible, priority will be given to purchasing from local business.

6.2 Management will request price lists from a minimum of two suppliers where the amount of the purchase is not less than $20,000.00 and normal business practices will be followed.

6.3 Sealed bids will be required for all purchases in excess of $20,000.00.

6.4 All tenders and bids must be sealed or they will be considered void. All tenders and bids will be opened and evaluated by not less than one Management personnel and the Board Chairman or his designate. The President / CEO will accept or reject all properly received bids and all tenderers will be so notified in writing. The lowest tender will not necessarily be accepted.

APPENDIX 4-B

2011 FEDERAL AND ONTARIO TAX RETURN

Corporate Taxpayer Summary

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Corporate information

Corporation's name . . . . SIOUX LOOKOUT HYDRO INC.

Taxation Year . . . . 2011-01-01 to 2011-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . N

Corporation is related . . . . N

Number of associated corporations . . .

Type of corporation . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . -15,111

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		252,050
Taxable income		252,050
Donations		
Calculation of income from an active business carried on in Canada		252,050
Dividends paid		250,000
Dividends paid – Regular	250,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		95,779

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction	42,849	Part I	27,725	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	47,850
Investment tax credits		Other*		Surtax credit	
Abatement/Other*	25,205	Provincial or territorial tax	5,014	Other*	
				Balance due/refund (–)	-15,111

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Unused surtax credit (Schedule 37)	7,032
Cumulative eligible capital	110,590

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	252,050		
Taxable income	252,050		
% Allocation	100.00		
Attributed taxable income	252,050		
Surtax		N/A	N/A
Tax payable before deduction*	29,611		
Deductions and credits	18,268		
Net tax payable	11,343		
Attributed taxable capital			N/A
Capital tax payable**			N/A
Total tax payable***	11,343		
Instalments and refundable credits	6,329		
Balance due/Refund (-)	5,014		

* For Québec, this includes special taxes and logging operations.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
SIOUX LOOKOUT HYDRO INC.	5,919,911	5,919,911	3,019,989	3,019,989
Total	5,919,911	5,919,911	3,019,989	3,019,989

Québec

Corporate name	Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30)	Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18)	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total					

Ontario

Corporate name	Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514)	Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515)	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total			

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)	Net paid up capital – BC capital tax on financial institutions (FIN 689)	BC paid up capital – BC capital tax on financial institutions (FIN 689)
Total				

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2012-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-01-31	3,256			3,256
2012-02-29	3,256			3,256
2012-03-31	3,256			3,256
2012-04-30	3,256			3,256
2012-05-31	3,256			3,256
2012-06-30	3,256			3,256
2012-07-31	3,256			3,256
2012-08-31	3,256			3,256
2012-09-30	3,256			3,256
2012-10-31	3,256			3,256
2012-11-30	3,256			3,256
2012-12-31	3,252			3,252
Total	39,068			39,068

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
		47,850

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	47,850	A
Total instalments credited to the taxation year per T9	47,850	B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
SIOUX LOOKOUT HYDRO INC.	87053 8170 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				308,167 A
Add:				
Provision for income taxes – current		101	32,739	
Provision for income taxes – deferred		102	-3,007	
Interest and penalties on taxes		103	169	
Amortization of tangible assets		104	304,302	
Non-deductible meals and entertainment expenses		121	1,283	
Subtotal of additions			335,486 ▶	335,486
Other additions:				
Miscellaneous other additions:				
603 Provincial Apprenticeship Training Tax Credit	6,329			
Total	6,329	293	6,329	
604 Federal Investment Tax Credits	2,000			
Total	2,000	294	2,000	
Subtotal of other additions		199	8,329 ▶	8,329
Total additions		500	343,815 ▶	343,815
Deduct:				
Capital cost allowance from Schedule 8		403	358,654	
Cumulative eligible capital deduction from Schedule 10		405	8,324	
Subtotal of deductions			366,978 ▶	366,978
Other deductions:				
Miscellaneous other deductions:				
700 Change in sick leave and employee benefits		390	443	
701 Smart meter variance accounts		391	32,511	
704				
Total		394		
Subtotal of other deductions		499	32,954 ▶	32,954
Total deductions		510	399,932 ▶	399,932
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				252,050

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T2 SCH 1 E (10)

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
SIOUX LOOKOUT HYDRO INC.	87053 8170 RC0001	2011-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

(Columns B, C and D: Complete if payer corporation is connected)

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270
					J

(Columns G and H: Complete if payer corporation is connected)

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

A	B	C	D	D1
Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total

Total taxable dividends paid in the tax year to other than connected corporations		450	250,000
Eligible dividends (included in line 450)	450a		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)		460	250,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			250,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	250,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
	Subtotal	►	
Total taxable dividends paid in the tax year that qualify for a dividend refund			250,000

SCHEDULE 5

Canada Revenue Agency / Agence du revenu du Canada

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
SIOUX LOOKOUT HYDRO INC.	87053 8170 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Canada

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
252,050	252,050	252,050	11,343

Ontario basic income tax (from Schedule 500)	270	29,611		
Deduct: Ontario small business deduction (from schedule 500)	402	18,268		
Subtotal		11,343	11,343	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272			
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal				B6
Subtotal (amount A6 **plus** amount B6)			11,343	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			11,343	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			11,343	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			11,343	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282			
Subtotal				H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			11,343	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario apprenticeship training tax credit (from Schedule 552)	454	6,329		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Other Ontario tax credits				
Subtotal		6,329	6,329	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		5,014	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	5,014

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

SCHEDULE 8

Canada Revenue Agency | Agence du revenu du Canada

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
SIOUX LOOKOUT HYDRO INC.	87053 8170 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Net adjustments** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **** **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1	BUILDING	63,823			0		63,823	4	0	0	2,553	61,270
2.	1	DISTRIBUTION	3,978,726			0		3,978,726	4	0	0	159,149	3,819,577
3.	8	TOOLS & OFFICE EQUIP	33,315	4,968		0	2,484	35,799	20	0	0	7,160	31,123
4.	10	AUTO & COMPUTER	86,692			0		86,692	30	0	0	26,008	60,684
5.	45		147			0		147	45	0	0	66	81
6.	47		1,693,785	230,428		0	115,214	1,808,999	8	0	0	144,720	1,779,493
7.	50		7,391	2,337		0	1,169	8,559	55	0	0	4,707	5,021
8.	8	Tools and software	3,026			0		3,026	20	0	0	605	2,421
9.	12			22,500		0	11,250	11,250	100	0	0	11,250	11,250
10.	12	Small Tools		2,436		0		2,436	100	0	0	2,436	
		Totals	5,866,905	262,669			130,117	5,999,457				358,654	5,770,920

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		262,669		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Smart Meters	+	-10,825		
Total additions per books	=	251,844	►	251,844
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Construction in progress	+	8,091		
Total proceeds per books	=	8,091	► –	8,091
Depreciation and amortization per accounts – Schedule 1			–	304,302
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	-60,549

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		4,467,727
Opening net book value	–	4,528,276
Net change per financial statements	=	-60,549

If the amounts from the tax return and the financial statements differ, explain why below.

SCHEDULE 10

Canada Revenue Agency | Agence du revenu du Canada

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
SIOUX LOOKOUT HYDRO INC.	87053 8170 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 118,914 A

Add: Cost of eligible capital property acquired during the taxation year . . . . **222** ______

Other adjustments . . . . **226** ______

Subtotal (line 222 plus line 226) ______ x 3 / 4 = ______ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** ______ x 1 / 2 = ______ C

amount B minus amount C (if negative, enter "0") ______ ▶ ______ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** ______ E

Subtotal (add amounts A, D, and E) **230** 118,914 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** ______ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** ______ H

Other adjustments . . . . **246** ______ I

(add amounts G,H, and I) ______ x 3 / 4 = **248** ______ J

Cumulative eligible capital balance (amount F minus amount J) . . . . 118,914 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . **249** ______

amount K 118,914

less amount from line 249 ______

Current year deduction . . . . 118,914 x 7.00 % = **250** 8,324 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 8,324 ▶ 8,324 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 110,590 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3				
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4				
Line 3 minus line 4 (if negative, enter "0")		►			5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7				
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8				
Subtotal (line 7 plus line 8)	409	►			9	
Line 6 minus line 9 (if negative, enter "0")				►		O
Line N minus line O (if negative, enter "0")						P
Line 5				x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")						R
Amount R				x 2 / 3 =		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410		

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
SIOUX LOOKOUT HYDRO INC.	87053 8170 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder			Percentage common shares	Percentage preferred shares
		Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number		
	100	200	300	350	400	500
1	Corporation of the Town of Sioux Lookout (Corporatior	10698 4859 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

SCHEDULE 55

Canada Revenue Agency / Agence du revenu du Canada

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
SIOUX LOOKOUT HYDRO INC.	87053 8170 RC0001	2011-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		250,000			
Total taxable dividends paid in the tax year	100	250,000			
Total eligible dividends paid in the tax year			150		
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160		
Excessive eligible dividend designation (line 150 **minus** line 160)					A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC * (amount A **multiplied** by 20 %)			190		

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)					B
Part III.1 tax on excessive eligible dividend designations – Other corporations * (amount B **multiplied** by 20 %)			290		

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

APPENDIX 4-C

NOTICES OF ASSESSMENT

Canada Revenue Agency | Agence du revenu du Canada

Winnipeg MB R3C 3M2

RECEIVED
MAY 13 2010

Date of mailing	May 11, 2010
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2009

0003256

SIOUX LOOKOUT HYDRO INC
PO BOX 908
SIOUX LOOKOUT ON P8T 1B3

CORPORATION NOTICE OF ASSESSMENT

RESULTS

This notice explains the results of our assessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Assessment :	$	0.00
Prior balance:	$	0.00
		=================
Total balance:	$	0.00

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency | Agence du revenu du Canada

SIOUX LOOKOUT HYDRO INC

Date of mailing	May 11, 2010
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2009

CORPORATION NOTICE OF ASSESSMENT

SUMMARY OF ASSESSMENT

	$ Reported	$ Assessed
Federal Tax:		
Part I	0.00	0.00
Part I.3	0.00	0.00
Part II	0.00	0.00
Part III.1	0.00	0.00
Part IV	0.00	0.00
Part IV.1	0.00	0.00
Part VI	0.00	0.00
Part VI.1	0.00	0.00
Part XIII.1	0.00	0.00
Part XIV	0.00	0.00
Total Federal Tax:		$ 0.00
Net balance:		$ 0.00
Result of this assessment:		$ 0.00
Prior balance:		$ 0.00
Total balance:		$ 0.00

Linda Lizotte-MacPherson
Commissioner of Revenue

EXPLANATION

We have revised the cumulative eligible capital balance at the end of the tax year to $155,379.00, to agree with the calculated amount.

We have revised the taxable income for the purpose of the small business deduction to $411,709.00, to agree with the calculated amount.

We have revised the GRIP opening balance on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to agree with our records.

We have revised the taxable income for the year before specified future tax consequences on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to $411,709.00, which agrees with the taxable income on the T2 return.

We have revised the T2 return amount on line 400, 405, 410, or 425 reported on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to $411,709.00, to agree with the calculated amount.

We have revised the GRIP at the end of the year on Schedule 55, "Part III.1 Tax on Excessive Eligible Dividend Designations," to $0.00, to agree with the amount on Schedule 53, "General Rate Income Pool (GRIP) Calculation."

For general information regarding filing an objection, determining a corporation's losses, or reassessment periods, please refer to the "T2 Corporation Income Tax Guide," or visit our Web site at www.cra.gc.ca.

Please visit www.cra.gc.ca/mybusinessaccount to access your business information online.

For information about online requests available to business clients, visit www.cra.gc.ca/requests-business. This service allows clients to electronically

Date of mailing	May 11, 2010
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2009

0003257

CORPORATION NOTICE OF ASSESSMENT

request certain financial actions, additional remittance vouchers and other communication products, as well as reproductions of previously issued correspondence.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

For information visit www.cra.gc.ca or contact:

Business Enquiries: 1-800-959-5525
Winnipeg Tax Centre
66 Stapon Road
Winnipeg MB R3C 3M2
Fax 204-984-0418

Thunder Bay TSO

Detach and return this **REMITTANCE FORM** with your payment.

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800280

35
PX5003

Taxation Year End: (YYYYMMDD)	
Payment Amount:	$
Taxation Year End: (YYYYMMDD)	20091231
Payment Amount:	$
Total Payment Enclosed:	$

SIOUX LOOKOUT HYDRO INC.
C/O GORD MAKI
25 FIFTH AVE
PO BOX 908
SIOUX LOOKOUT ON
P8T 1B3

10 HPL

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2009/01/01 **to** 2009/12/31

	Account No.	Assessment Date (year, month, day)	Page
SIOUX LOOKOUT HYDRO INC.	**1800280**	2010/06/15	1 of 1

ASSESSMENT NO. 122

Tax: Federal and Provincial PIL		69,738.00
Assessment Interest		471.94
Total Assessment Liability		70,209.94

SUMMARY OF 2009/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	69,738.00CR	
Sub-Total		69,738.00CR
TAXATION YEAR BALANCE DUE **		471.94

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

**Remember to include additional interest due with your payment. Interest on the balance is compounded daily from the date of this Notice/Statement until payment is received by the Ontario Electricity Financial Corporation (OEFC) The current interest rate is 0.0136986%.

RECEIVED
JUN 21 2010

PX5003 004

Detach and return this REMITTANCE FORM with your payment.

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800280

35
PX5005

SIOUX LOOKOUT HYDRO INC.
C/O GORD MAKI
25 FIFTH AVE
PO BOX 908
SIOUX LOOKOUT ON
P8T 1B3

10 HPL

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 20081231

Payment Amount: $

Total Payment Enclosed: $

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Reassessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2008/01/01 **to** 2008/12/31

	Account No.	Reassessment Date (year, month, day)	Page
SIOUX LOOKOUT HYDRO INC.	**1800280**	2010/06/22	4 of 4

REASSESSMENT NO. 145 REPLACING ASSESSMENT DATED: 2009/05/15

Tax: Federal and Provincial PIL		27,001.00
Assessment Interest		308.61
Total Reassessment Liability		27,309.61

SUMMARY OF 2008/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	33,810.10CR	
Interest	246.60CR	
Refunds	2,528.59	
Sub-Total		31,528.11CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		4,218.50CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

As per amended return.

PX5005 004

Detach and return this **REMITTANCE FORM** with your payment.

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800280

35
PX5005

Taxation Year End: (YYYYMMDD) [ ]

Payment Amount: $ [ ]

SIOUX LOOKOUT HYDRO INC.
C/O GORD MAKI
25 FIFTH AVE
PO BOX 908
SIOUX LOOKOUT ON
P8T 1B3

Taxation Year End: (YYYYMMDD) 20071231

Payment Amount: $ [ ]

Total Payment Enclosed: $ [ ]

10 HPL

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Reassessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2007/01/01 **to** 2007/12/31

	Account No.	Reassessment Date (year, month, day)	Page
SIOUX LOOKOUT HYDRO INC.	**1800280**	2010/06/22	3 of 4

REASSESSMENT NO. 137 REPLACING REASSESSMENT DATED: 2008/08/14

Tax: Federal and Provincial PIL		29,320.00
Assessment Interest		233.27
Total Reassessment Liability		29,553.27

SUMMARY OF 2007/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	61,583.74CR	
Refunds	30,311.37	
Sub-Total		31,272.37CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		1,719.10CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

As per amended return.

PX5005 004

Tax (Re)Assessment Enquiries:	• 1 866 ONT-TAXS (1 866 668-8297) ext. 21113 • FAX 416 218-3276	• TTY 1 800 263-7776 • ontario.ca/revenue	**Account Billing Enquiries & Change of Address Information:**	• 1 866 ONT-TAXS (1 866 668-8297) • FAX 905 433-5197

Detach and return this **REMITTANCE FORM** with your payment.

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800280

35
PX5005

Taxation Year End: (YYYYMMDD)

Payment Amount: $, , .

SIOUX LOOKOUT HYDRO INC.
C/O GORD MAKI
25 FIFTH AVE
PO BOX 908
SIOUX LOOKOUT ON
P8T 1B3

10 HPL

Taxation Year End: (YYYYMMDD) 2 0 0 6 1 2 3 1

Payment Amount: $, , .

Total Payment Enclosed: $, , .

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Reassessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2006/01/01 **to** 2006/12/31

	Account No.	Reassessment Date (year, month, day)	Page
SIOUX LOOKOUT HYDRO INC.	**1800280**	2010/06/22	2 of 4

REASSESSMENT NO. 131 REPLACING ASSESSMENT DATED: 2007/05/17

Tax: Federal and Provincial PIL		34,477.00
Assessment Interest		716.17
Total Reassessment Liability		35,193.17

SUMMARY OF 2006/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	37,302.13CR	
Small Balance Adjustment	1.11CR	
Sub-Total		37,303.24CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		2,110.07CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

As per amended return.

PX5005 004

Detach and return this REMITTANCE FORM with your payment.

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800280

35
PX5005

SIOUX LOOKOUT HYDRO INC.
C/O GORD MAKI
25 FIFTH AVE
PO BOX 908
SIOUX LOOKOUT ON
P8T 1B3

10 HPL

RECEIVED
JUN 28 2010

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 20051231

Payment Amount: $

Total Payment Enclosed: $

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Reassessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2005/01/01 **to** 2005/12/31

	Account No.	Reassessment Date (year, month, day)	Page
SIOUX LOOKOUT HYDRO INC.	**1800280**	2010/06/22	1 of 4

REASSESSMENT NO. 125 REPLACING REASSESSMENT DATED: 2007/03/15

Tax: Federal and Provincial PIL		31,622.00
Assessment Interest		1,426.73
Total Reassessment Liability		33,048.73

SUMMARY OF 2005/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	58,734.95CR	
Refunds	30,495.29	
Small Balance Adjustment	0.01	
Sub-Total		28,239.65CR
TAXATION YEAR BALANCE DUE **		4,809.08

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

As per amended return.

**Remember to include additional interest due with your payment. Interest on the balance is compounded daily from the date of this Notice/Statement until payment is received by the Ontario Electricity Financial Corporation (OEFC) The current interest rate is 0.0136986%.

PX5005 004

Canada Revenue Agency | Agence du revenu du Canada

Winnipeg MB R3C 3M2

RECEIVED

Date of mailing	April 27, 2011
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2010

0003425

SIOUX LOOKOUT HYDRO INC
PO BOX 908
SIOUX LOOKOUT ON P8T 1B3

CORPORATION NOTICE OF ASSESSMENT

RESULTS

Thank you for choosing to use our Corporation Internet Filing service.

This notice explains the results of our assessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Assessment :	$	0.00
Prior balance:	$	0.00
		================
Total balance:	$	0.00

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency | Agence du revenu du Canada

SIOUX LOOKOUT HYDRO INC

Date of mailing	April 27, 2011
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2010

CORPORATION NOTICE OF ASSESSMENT

SUMMARY OF ASSESSMENT

	$ Reported	$ Assessed
Federal Tax:		
Part I	0.00	0.00
Part I.3	0.00	0.00
Part II	0.00	0.00
Part III.1	0.00	0.00
Part IV	0.00	0.00
Part IV.1	0.00	0.00
Part VI	0.00	0.00
Part VI.1	0.00	0.00
Part XIII.1	0.00	0.00
Part XIV	0.00	0.00
Total Federal Tax:		$ 0.00
Net balance:		$ 0.00
Result of this assessment:		$ 0.00
Prior balance:		$ 0.00
Total balance:		$ 0.00

Linda Lizotte-MacPherson
Commissioner of Revenue

EXPLANATION

We have revised the cumulative eligible capital balance at the end of the tax year to $155,379.00, to agree with the calculated amount.

We have revised the taxable income for the purpose of the small business deduction to $591,626.00, to agree with the calculated amount.

We have revised the GRIP opening balance on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to agree with our records.

We have revised the taxable income for the year before specified future tax consequences on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to $591,626.00, which agrees with the taxable income on the T2 return.

We have revised the T2 return amount on line 400, 405, 410, or 425 reported on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to $500,000.00, to agree with the calculated amount.

We have revised the GRIP at the end of the tax year on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to agree with the calculated amount.

We have revised the GRIP at the end of the year on Schedule 55, "Part III.1 Tax on Excessive Eligible Dividend Designations," to $63,222.00, to agree with the amount on Schedule 53, "General Rate Income Pool (GRIP) Calculation."

For general information regarding filing an objection, determining a corporation's losses, or reassessment periods, please refer to the "T2 Corporation Income Tax Guide," or visit our Web site at www.cra.gc.ca.

Please visit www.cra.gc.ca/mybusinessaccount to access your business information online.

SIOUX LOOKOUT HYDRO INC

Date of mailing	April 27, 2011
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2010

0003426

CORPORATION NOTICE OF ASSESSMENT

For information about online requests available to business clients, visit www.cra.gc.ca/requests-business. This service allows clients to electronically request certain financial actions, additional remittance vouchers and other communication products, as well as reproductions of previously issued correspondence.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

For information visit www.cra.gc.ca or contact:

Business Enquiries: 1-800-959-5525
Winnipeg Tax Centre
66 Stapon Road
Winnipeg MB R3C 3M2
Fax 204-984-0418

Thunder Bay TSO

Ontario

Ministry of Revenue
33 King St W
PO Box 622
Oshawa ON L1H 8H6

RECEIVED
SEP 30 2011

HPL - tL059

0000191

SIOUX LOOKOUT HYDRO INC.
ATTENTION: C/O GORD MAKI
25 FIFTH AVE
PO BOX 908
SIOUX LOOKOUT ON P8T 1B3

Issue Date	22-Sep-2011
Identification No.	1800280
Reference No.	L0448519552

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2010	**Return As Filed**
Total Federal Tax	$39,157.00
Total Ontario Tax	$18,693.00
Total Credits	($10,000.00)
Loss Carry-back	$0.00
Total Tax Payable	$47,850.00
Interest	$169.33
Current Penalty	$0.00
Credits/Payments	($48,019.33)
Total Assessment	**$0.00**

As of 22-Sep-2011, including the amount assessed above, you have an overall credit balance on your account of ($16,323.67).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Tax Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Revenue at the number listed below.

Ministry use only

Enquiries 1 866 ONT-TAXS 1 866 668-8297 Fax 1 866 888-3850 Teletypewriter (TTY) 1 800 263-7776 Internet **ontario.ca/revenue**

Canada Revenue Agency | Agence du revenu du Canada

Winnipeg MB R3C 3M2

Date of mailing
April 26, 2012
Business Number
87053 8170 RC0001
Tax year-end
December 31, 2011

0004331

SIOUX LOOKOUT HYDRO INC
PO BOX 908
SIOUX LOOKOUT ON P8T 1B3

CORPORATION NOTICE OF ASSESSMENT

RESULTS

Thank you for choosing to use our Corporation Internet Filing service.

This notice explains the results of our assessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Assessment :	$	0.00
Prior balance:	$	0.00
		================
Total balance:	$	0.00

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency | Agence du revenu du Canada

SIOUX LOOKOUT HYDRO INC

Date of mailing	April 26, 2012
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2011

CORPORATION NOTICE OF ASSESSMENT

SUMMARY OF ASSESSMENT

	$ Reported	$ Assessed
Federal Tax:		
Part I	0.00	0.00
Part I.3	0.00	0.00
Part II	0.00	0.00
Part III.1	0.00	0.00
Part IV	0.00	0.00
Part IV.1	0.00	0.00
Part VI	0.00	0.00
Part VI.1	0.00	0.00
Part XIII.1	0.00	0.00
Part XIV	0.00	0.00
Total Federal Tax:		$ 0.00
Net balance:		$ 0.00
Result of this assessment:		$ 0.00
Prior balance:		$ 0.00
Total balance:		$ 0.00

Linda Lizotte-MacPherson
Commissioner of Revenue

EXPLANATION

We have revised the cumulative eligible capital balance at the end of the tax year to $155,379.00, to agree with the calculated amount.

We have revised the taxable income for the purpose of the small business deduction to $615,741.00, to agree with the calculated amount.

We have revised the GRIP opening balance on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to agree with our records.

We have revised the taxable income for the year before specified future tax consequences on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to $615,741.00, which agrees with the taxable income on the T2 return.

We have revised the T2 return amount on line 400, 405, 410, or 425 reported on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to $500,000.00, to agree with the calculated amount.

We have revised the GRIP at the end of the tax year on Schedule 53, "General Rate Income Pool (GRIP) Calculation," to agree with the calculated amount.

For general information regarding filing an objection, determining a corporation's losses, or reassessment periods, please refer to the "T2 Corporation Income Tax Guide" or visit our Web site at www.cra.gc.ca.

Please visit www.cra.gc.ca/mybusinessaccount to access your business information online.

For information about online requests available to business clients, visit www.cra.gc.ca/requests-business. This service allows clients to electronically request certain financial actions, additional remittance vouchers and other

SIOUX LOOKOUT HYDRO INC

Date of mailing	April 26, 2012
Business Number	87053 8170 RC0001
Tax year-end	December 31, 2011

0004332

CORPORATION NOTICE OF ASSESSMENT

communication products, and reproductions of previously issued correspondence.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

For information visit www.cra.gc.ca or contact:

Business Enquiries: 1-800-959-5525
Winnipeg Tax Centre
66 Stapon Road
Winnipeg MB R3C 3M2
Fax 204-984-0418

Thunder Bay TSO

Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL059

000005

SIOUX LOOKOUT HYDRO INC.
ATTENTION: C/O GORD MAKI
25 FIFTH AVE
PO BOX 908
SIOUX LOOKOUT ON P8T 1B3

Issue Date	23-Apr-2012
Business No.	870538170TW0001
Reference No.	L1926404992

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2011	**Return As Filed**
Total Federal Tax	$27,725.00
Total Ontario Tax	$11,343.00
Total Credits	($6,329.00)
Loss Carry-back	$0.00
Total Tax Payable	$32,739.00
Interest	$207.42
Current Penalty	$0.00
Credits/Payments	($32,946.42)
Total Assessment	**$0.00**

As of 23-Apr-2012, including the amount assessed above, you have an overall credit balance on your account of ($2,941.08).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

Ministry use only

0183B (2010-05)

APPENDIX 4-D

OPA 2011 FINAL EVALUATION REPORT

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2011 Results Report.

Despite some of the inertial challenges in 2011 with program start up, on average, year one province-wide forecasts were met and the year finished out with strong momentum which continues to build 2012. There are still challenges for LDCs of all sizes and we are committed to ensuring LDCs are successful in meeting their objectives. We look forward to further dialogue to discover opportunities to improve the current program suite with local program opportunities, best practices and successes to better reach our customers in the years to come.

This report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. Between the draft and final reports several improvements were made to improve clarity and transparency based on feedback provided by LDCs, such as: the addition of a glossary tab, total adjustments to savings are now broken out into both the realization rate and net-to-gross ratio for both peak demand and energy savings and modifications were made to the methodology tab. We invite you to continue to provide your feedback.

All results are now considered final for 2011. Any additional 2011 program activity not captured will be reported in the Final 2012 Results Report. Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2012.

Sincerely,
Andrew Pride

Table of Contents

Summary	Provides a "snapshot" of your LDC's OPA-Contracted Province-Wide Program performance in 2011: progress to target using 2 scenarios, sector breakdown and progress against the LDC community.
LDC-Specific Data: table formats, section references and table numbers align with the OEB Reporting Template	
2.3 Results Participation - LDC	Breakdown of initiative-level participation in 2011 for your LDC.
2.5.1 Evaluation Findings	Provides a summary of the province-wide evaluation findings for each initiative and highlights which initiatives were not evaluated.
2.5.2 Results - LDC	Provides LDC-specific initiative-level results (net and gross peak demand and energy savings, realization rates, net-to-gross ratios and how each initiative contributes to target)
3.1.1 Summary - LDC	Provides a portfolio level view of achievement towards your OEB targets in 2011. Contains space to input LDC-specific progress to milestones set out in your CDM Strategy.
Province-Wide Data: LDC performance in aggregate (province-wide results)	
Provincial - Participation	Breakdown of initiative-level participation in 2011 for the province.
Provincial - Results	Provides province-wide initiative-level results (net and gross peak demand and energy savings, realization rates, net-to-gross ratios and how each initiative contributes to target)
Provincial - Progress Summary	Provides a portfolio level view of provincial achievement towards province-wide OEB targets in 2011.
Methodology	Provides key equations, notes and an initiative-level breakdown of: how savings are attributed to LDCs, when the savings are considered to 'start' (i.e. what period the savings are attributed to) and how the savings are calculated.
Reference Tables	Provides the sector mapping used for Retrofit and the allocation methodology table used in the consumer program when customer
Glossary	Contains definitions for terms used throughout the report.

OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

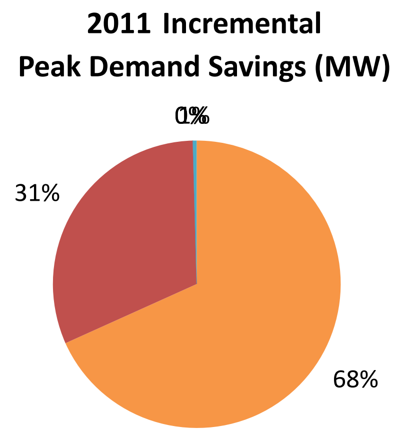
LDC: Sioux Lookout Hydro Inc.

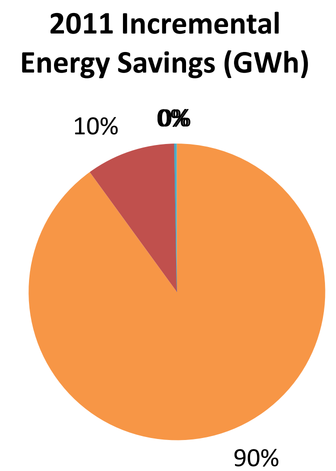
FINAL 2011 Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.0	**1.5%**	**1.5%**
Net Cumulative Energy Savings (GWh)	0.1	**7.4%**	**7.4%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector

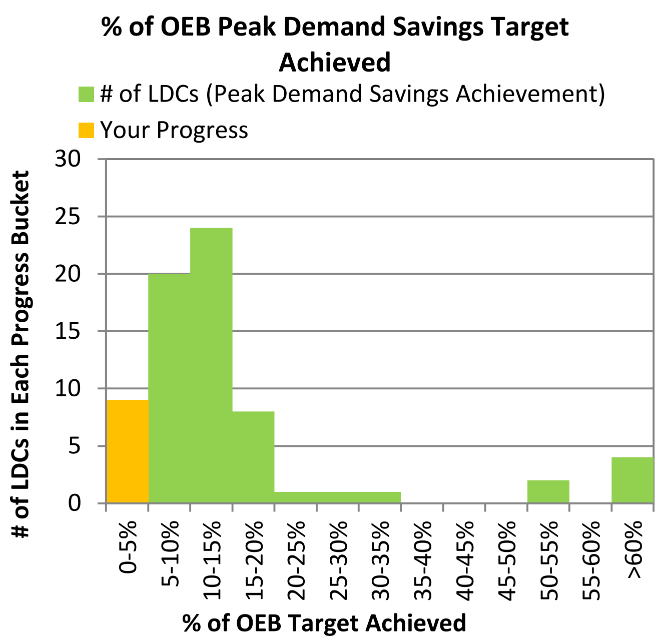




Consumer Program Total
Business Program Total
Industrial Program Total
Home Assistance Program Total
Pre-2011 Programs completed in 2011 Total

Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)



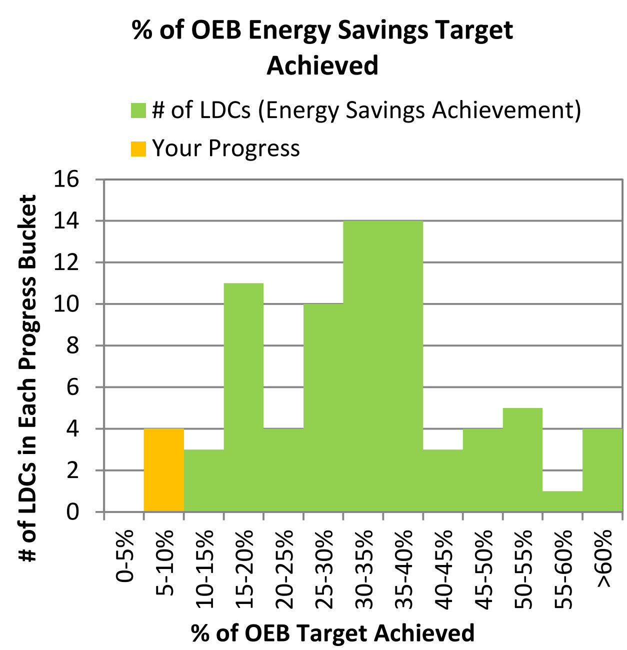


Table 1: Participation[1]

#	Initiative	Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	32
2	Appliance Exchange	Appliances	1
3	HVAC Incentives	Equipment	2
4	Conservation Instant Coupon Booklet	Products	420
5	Bi-Annual Retailer Event	Products	732
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	0
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	0
10	Direct Install Lighting	Projects	3
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	0
14	Commercial Demand Response (part of the Residential program schedule)	Devices	0
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	0
20	Demand Response 3	Facilities	0
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	0
23	High Performance New Construction	Projects	0
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

[1] Please see "Methodology" tab for more information regarding attributing savings to LDCs

[2] Results are based on completed incentive projects (see "Methodology" tab for more information)

[3] Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011

Table 3: OPA Province-Wide Evaluation Findings

#	Initiative	OPA Province-Wide Key Evaluation Findings
Consumer Program		

1	Appliance Retirement	* Overall participation continues to decline year over year
		    * Participation declined 17% from 2010 (from over 67,000 units in 2010 to over 56,000 units in 2011)
		* 97% of net resource savings achieved through the home pick-up stream
		    * Measure Breakdown: 66% refrigerators, 30% freezers, 4% Dehumidifiers and window air conditioners
		* 3% of net resource savings achieved through the Retailer pick-up stream
		    * Measure Breakdown: 90% refrigerators, 10% freezers
		* Net-to-Gross ratio for the initiative was 50%
		    * Measure-level free ridership ranges from 82% for the retailer pick-up stream to 49% for the home pick-up stream
		    * Measure-level spillover ranges from 3.7% for the retailer pick-up stream to 1.7% for the home pick-up stream

2	Appliance Exchange	* Overall eligible units exchanged declined by 36% from 2010 (from over 5,700 units in 2010 to
		    * Measure Breakdown: 75% window air conditioners, 25% dehumidifiers
		* Dehumidifiers and window air conditioners contributed almost equally to the net energy
		    * Dehumidifiers provide more than three times the energy savings per unit than window air conditioners
		* Window air conditioners contributed to 64% of the net peak demand savings achieved
		* Approximately 96% of consumers reported having replaced their exchanged units (as opposed to retiring the unit)
		* Net-to-Gross ratio for the initiative is consistent with previous evaluations (51.5%)

3	HVAC Incentives	* Total air conditioner and furnace installations increased by 14% (from over 95,800 units in 2010 to over 111,500 units in 2011)
		    * Measure Breakdown: 64% furnaces, 10% tier 1 air conditioners (SEER 14.5) and 26% tier 2 air conditioners (SEER 15)
		    * Measure breakdown did not change from 2010 to 2011
		* The HVAC Incentives initiative continues to deliver the majority of both the energy (45%) and demand (83%) savings in the consumer program
		    * Furnaces accounted for over 91% of energy savings achieved for this initiative
		* Net-to-Gross ratio for the initiative was 17% higher than 2010 (from 43% in 2010 to 60% in
		    * Increase due in part to the removal of programmable thermostats from the program, and an increase in the net-to-gross ratio for both Furnaces and Tier 2 air conditioners (SEER 15)

4	Conservation Instant Coupon Booklet	* Customers redeemed nearly 210,000 coupons, translating to nearly 560,000 products
		    * Majority of coupons redeemed were downloadable (~40%) or LDC-branded (~35%)
		    * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (37%), followed by multi-packs of specialty CFLs (17%)
		* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings
		* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed

		* Customers redeemed nearly 370,000 coupons, translating to over 870,000 products * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (49%), followed by multi-packs of specialty CFLs (16%)

#	Initiative	OPA Province-Wide Key Evaluation Findings
5	Bi-Annual Retailer Event	* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings * Standard CFLs and heavy duty outdoor timers were reintroduced to the initiative in 2011 and contributed more than 64% of the initiative's 2011 net annual energy savings * While the volume of coupons redeemed for heavy duty outdoor timers was relatively small (less than 1%), the measure accounted for 10% of net annual savings due to high per unit savings * Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed.
6	Retailer Co-op	* Initiative was not evaluated in 2011 due to low uptake. Verified Bi-Annual Retailer Event per unit assumptions and free-ridership rates were used to calculate net resource savings
7	Residential Demand Response	* Approximately 20,000 new devices were installed in 2011 * 99% of the new devices enrolled controlled residential central AC (CAC) * 2011 only saw 1 atypical event (in both weather and timing) that had limited participation * The ex ante impact developed through the 2009/2010 evaluations was maintained for 2011; residential CAC: 0.56 kW/device, commercial CAC: 0.64 kW/device, and Electric Water Heaters: 0.30 kW/device
8	Residential New Construction	* Initiative was not evaluated in 2011 due to limited uptake * Business case assumptions were used to calculate savings
Business Program		
9	Efficiency: Equipment Replacement	* Gross verified energy savings were boosted by lighting projects in the prescriptive and * Lighting projects overall were determined to have a realization rate of 112%; 116% when including interactive energy changes * On average, the evaluation found high realization rates as a result of both longer operating hours and larger wattage reductions than initial assumptions * Low realization rates for engineered lighting projects due to overstated operating hour assumptions * Custom non-lighting projects suffered from process issues such as: the absence of required M&V plans, the use of inappropriate assumptions , and the lack of adherence to the M&V plan * The final realization rate for summer peak demand was 94% * 84% was a result of different methodologies used to calculate peak demand savings * 10% due to the benefits from reduced air conditioning load in lighting retrofits * Overall net-to-gross ratios in the low 70's represent an improvement over the 2009 and Strict eligibility requirements and improvements in the pre-approval process contributed to the improvement in net-to-gross ratios
10	Direct Install Lighting	* Though overall performance is above expectations, participation continues to decline year over year as the initiative reaches maturity * 70% of province-wide resource savings persist to 2014 * Over 35% of the projects for 2011 included at least one CFL measure * Resource savings from CFLs in the commercial sector only persist for the industry standard of 3 years * Since 2009 the overall realization rate for this program has improved * 2011 evaluation recorded the highest energy realization rate to date at 89.5%

#	Initiative	OPA Province-Wide Key Evaluation Findings
		* The hours of use values were held constant from the 2010 evaluation and continue to be the main driver of energy realization rate * Lights installed in “as needed” areas (e.g., bathrooms, storage areas) were determined to have very low realization rates due to the difference in actual energy saved vs. reported savings
11	Existing Building Commissioning Incentive	* Initiative was not evaluated in 2011, no completed projects in 2011
12	New Construction and Major Renovation Incentive	* Initiative was not evaluated in 2011 due to low uptake * Assumptions used are consistent with preliminary reporting based on the 2010 Evaluation findings and consultation with the C&I Work Group (100% realization rate and 50% net-to-gross ratio)
13	Energy Audit	* The evaluation is ongoing. The sample size for 2011 was too small to draw reliable conclusions.
14	Commercial Demand Response (part of the Residential program schedule)	* See residential demand response (#7)
15	Demand Response 3 (part of the Industrial program schedule)	* See Demand Response 3 (#20)
Industrial Program		
16	Process & System Upgrades	* Initiative was not evaluated in 2011, no completed projects in 2011
17	Monitoring & Targeting	* Initiative was not evaluated in 2011, no completed projects in 2011
18	Energy Manager	* Initiative was not evaluated in 2011, no completed projects in 2011
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	* See Efficiency: Equipment Replacement (#9)
20	Demand Response 3	* Program performance for Tier 1 customers increased with DR-3 participants providing 75% * Industrial customers outperform commercial customers by provide 84% and 76% of contracted MW, respectively * Program continues to diversify but still remains heavily concentrated with less than 5% of * By increasing the number of contributors in each settlement account and implementation of the new baseline methodology the performance of the program is expected to increase
Home Assistance Program		
21	Home Assistance Program	* Initiative was not evaluated in 2011 due to low uptake * Business Case assumptions were used to calculate savings
Pre-2011 Programs completed in 2011		

#	Initiative	OPA Province-Wide Key Evaluation Findings
22	Electricity Retrofit Incentive Program	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (multifamily buildings 99% realization rate and 62% net-to-gross ratio and C&I buildings 77% realization rate and 52% net-to-gross ratio)
23	High Performance New Construction	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (realization rate of 100% and net-to-gross ratio of 50%)
24	Toronto Comprehensive	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
25	Multifamily Energy Efficiency Rebates	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
26	Data Centre Incentive Program	* Initiative was not evaluated
27	EnWin Green Suites	* Initiative was not evaluated

Table 5: Summarized Program Results

Program	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program Total	8	65,498	5	55,336
Business Program Total	2	6,447	2	5,986
Industrial Program Total	0	0	0	0
Home Assistance Program Total	0	0	0	0
Pre-2011 Programs completed in 2011 Total	0	348	0	174
Total OPA Contracted Province-Wide CDM Programs	**10**	**72,293**	**8**	**61,496**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	4	25,993	50%	52%	2	13,344
2	Appliance Exchange	100%	100%	0	219	52%	52%	0	113
3	HVAC Incentives	100%	100%	1	2,364	60%	60%	1	1,408
4	Conservation Instant Coupon Booklet	100%	100%	1	14,312	114%	111%	1	15,771
5	Bi-Annual Retailer Event	100%	100%	1	22,609	113%	110%	1	24,700
6	Retailer Co-op	-	-	0	0	-	-	0	0
7	Residential Demand Response	0%	0%	0	0	-	-	0	0
8	Residential New Construction	-	-	0	0	-	-	0	0
Business Program									
9	Efficiency: Equipment Replacement	-	-	0	0	-	-	0	0
10	Direct Install Lighting	108%	90%	2	6,447	93%	93%	2	5,986
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0
12	New Construction and Major Renovation Incentive	-	-	0	0	-	-	0	0
13	Energy Audit	-	-	0	0	-	-	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	0	0	-	-	0	0
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	0	0	n/a	n/a	0	0
Industrial Program									
16	Process & System Upgrades	-	-	0	0	-	-	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0
18	Energy Manager	-	-	0	0	-	-	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	-	-	0	0	-	-	0	0
20	Demand Response 3	84%	100%	0	0	n/a	n/a	0	0
Home Assistance Program									
21	Home Assistance Program	-	-	0	0	-	-	0	0
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	-	-	0	0	-	-	0	0
23	High Performance New Construction	100%	100%	0	348	50%	50%	0	174
24	Toronto Comprehensive	-	-	0	0	-	-	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	5	221,075
Business Program Total	2	23,945
Industrial Program Total	0	0
Home Assistance Program Total	0	0
Pre-2011 Programs completed in 2011 Total	0	696
Total OPA Contracted Province-Wide CDM Programs	**7**	**245,717**

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	2	53,172
2	Appliance Exchange	0	387
3	HVAC Incentives	1	5,632
4	Conservation Instant Coupon Booklet	1	63,083
5	Bi-Annual Retailer Event	1	98,801
6	Retailer Co-op	0	0
7	Residential Demand Response	0	0
8	Residential New Construction	0	0
Business Program			
9	Efficiency: Equipment Replacement	0	0
10	Direct Install Lighting	2	23,945
11	Existing Building Commissioning Incentive	0	0
12	New Construction and Major Renovation Incentive	0	0
13	Energy Audit	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0	0
15	Demand Response 3 (part of the Industrial program schedule)	0	0
Industrial Program			
16	Process & System Upgrades	0	0
17	Monitoring & Targeting	0	0
18	Energy Manager	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	0	0
20	Demand Response 3	0	0
Home Assistance Program			
21	Home Assistance Program	0	0
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	0	0
23	High Performance New Construction	0	696
24	Toronto Comprehensive	0	0
25	Multifamily Energy Efficiency Rebates	0	0
26	Data Centre Incentive Program	0	0
27	EnWin Green Suites	0	0

Assumes demand response resources have a persistence of 1 year

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Yellow cells are intended for the LDC to input information to complete their OEB Reporting Template.

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.01	0.01	0.01	0.01
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				**0.01**
Sioux Lookout Hydro Inc. 2014 Annual CDM Capacity Target:				**0.51**
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				**1.46%**
LDC Milestone submitted for 2011				**-%**
Variance				

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.06	0.06	0.06	0.06	0.25
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**0.25**
Sioux Lookout Hydro Inc. 2011-2014 Cumulative CDM Energy Target:					**3.32**
Verified Portion of Cumulative Energy Target Achieved (%):					**7.40%**
LDC Milestone submitted for 2011					**-%**
Variance					

Table P1: Province-Wide Participation

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	56,110
2	Appliance Exchange	Appliances	3,688
3	HVAC Incentives	Equipment	111,587
4	Conservation Instant Coupon Booklet	Products[4]	559,462
5	Bi-Annual Retailer Event	Products[5]	870,332
6	Retailer Co-op	Products	152
7	Residential Demand Response	Devices	19,577
8	Residential New Construction	Houses	7
Business Program			
9	Efficiency: Equipment Replacement	Projects	2,516
10	Direct Installed Lighting	Projects	20,297
11	Existing Building Commissioning Incentive	Buildings	-
12	New Construction and Major Renovation Incentive	Buildings	10
13	Energy Audit	Audits	103
14	Commercial Demand Response (part of the Residential program schedule)	Devices	264
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	148
Industrial Program			
16	Process & System Upgrades[2]	Projects	-
17	Monitoring & Targeting[2]	Projects	-
18	Energy Manager[2 3]	Managers	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)[1]	Projects	433
20	Demand Response 3	Facilities	134
Home Assistance Program			
21	Home Assistance Program	Homes	46
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	2,023
23	High Performance New Construction	Projects	145
24	Toronto Comprehensive	Projects	553
25	Multifamily Energy Efficiency Rebates	Projects	110
26	Data Centre Incentive Program	Projects	5
27	EnWin Green Suites	Projects	3

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers with completed projects*

[4] *209,693 valid coupons redeemed*

[5] *369,446 valid coupons redeemed*

Table P2: Province-Wide Results

Program	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program Total	73,757	192,379,633	49,123	133,519,668
Business Program Total	78,048	251,304,448	64,594	198,124,227
Industrial Program Total	68,648	41,493,145	57,099	31,947,577
Home Assistance Program Total	4	56,119	2	39,283
Pre-2011 Programs completed in 2011 Total	87,169	460,822,079	44,833	241,853,020
Total OPA Contracted Province-Wide CDM Programs	**307,626**	**946,055,425**	**215,651**	**605,483,775**

#	Initiative	Realization Rate: Peak Demand Savings	Realization Rate: Energy Savings	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net-to-Gross Ratio: Peak Demand Savings	Net-to-Gross Ratio: Energy Savings	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	6,750	45,971,627	51%	51%	3,299	23,005,812
2	Appliance Exchange	100%	100%	719	873,531	51%	51%	371	450,187
3	HVAC Incentives	100%	100%	53,209	99,413,430	60%	60%	32,037	59,437,670
4	Conservation Instant Coupon Booklet	100%	100%	1,184	19,192,453	114%	111%	1,344	21,211,537
5	Bi-Annual Retailer Event	100%	100%	1,504	26,899,265	112%	110%	1,681	29,387,468
6	Retailer Co-op	100%	100%	0	3,917	68%	68%	0	2,652
7	Residential Demand Response	n/a	n/a	10,390	23,597	n/a	n/a	10,390	23,597
8	Residential New Construction	100%	100%	0	1,813	41%	41%	0	743
Business Program									
9	Efficiency: Equipment Replacement	106%	91%	34,201	184,070,265	72%	74%	24,467	136,002,258
10	Direct Installed Lighting	108%	93%	22,155	65,777,197	108%	93%	23,724	61,076,701
11	Existing Building Commissioning Incentive	-	-	-	-	-	-	-	-
12	New Construction and Major Renovation Incentive	50%	50%	247	823,434	50%	50%	123	411,717
13	Energy Audit	-	-	-	-	-	-	-	-
14	Commercial Demand Response (part of the Residential program schedule)	n/a	n/a	55	131	n/a	n/a	55	131
15	Demand Response 3 (part of the Industrial program schedule)	76%	n/a	21,390	633,421	n/a	n/a	16,224	633,421
Industrial Program									
16	Process & System Upgrades	-	-	-	-	-	-	-	-
17	Monitoring & Targeting	-	-	-	-	-	-	-	-
18	Energy Manager	-	-	-	-	-	-	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	111%	91%	6,372	38,412,408	72%	75%	4,615	28,866,840
20	Demand Response 3	84%	n/a	62,276	3,080,737	n/a	n/a	52,484	3,080,737
Home Assistance Program									
21	Home Assistance Program	100%	100%	4	56,119	70%	70%	2	39,283
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	80%	80%	40,418	223,956,390	54%	54%	21,550	120,492,549
23	High Performance New Construction	100%	100%	10,197	52,371,183	49%	49%	5,098	26,185,591
24	Toronto Comprehensive	113%	113%	33,467	174,070,574	50%	52%	15,805	86,964,886
25	Multifamily Energy Efficiency Rebates	93%	93%	2,553	9,774,792	78%	78%	1,981	7,595,683
26	Data Centre Incentive Program	100%	100%	81	533,038	100%	100%	81	533,038
27	EnWin Green Suites	100%	100%	453	116,102	70%	70%	317	81,272

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets: Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	38,405	534,017,835
Business Program Total	41,048	767,657,790
Industrial Program Total	4,613	118,543,019
Home Assistance Program Total	2	157,134
Pre-2011 Programs completed in 2011 Total	44,833	967,412,079
Total OPA Contracted Province-Wide CDM Programs	**128,901**	**2,387,787,856**

#	Initiative	Contribution to Targets: Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	3,160	91,903,303
2	Appliance Exchange	181	1,930,651
3	HVAC Incentives	32,037	237,750,681
4	Conservation Instant Coupon Booklet	1,344	84,846,148
5	Bi-Annual Retailer Event	1,681	117,549,874
6	Retailer Co-op	0	10,607
7	Residential Demand Response	0	23,597
8	Residential New Construction	0	2,973
Business Program			
9	Efficiency: Equipment Replacement	24,438	543,856,392
10	Direct Installed Lighting	16,486	221,520,977
11	Existing Building Commissioning Incentive	-	-
12	New Construction and Major Renovation Incentive	123	1,646,869
13	Energy Audit	-	-
14	Commercial Demand Response (part of the Residential program schedule)	0	131
15	Demand Response 3 (part of the Industrial program schedule)	0	633,421
Industrial Program			
16	Process & System Upgrades	-	-
17	Monitoring & Targeting	-	-
18	Energy Manager	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	4,613	115,462,282
20	Demand Response 3	0	3,080,737
Home Assistance Program			
21	Home Assistance Program	2	157,134
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	21,550	481,970,197
23	High Performance New Construction	5,098	104,742,366
24	Toronto Comprehensive	15,805	347,859,545
25	Multifamily Energy Efficiency Rebates	1,981	30,382,733
26	Data Centre Incentive Program	81	2,132,152
27	EnWin Green Suites	317	325,086

Assumes demand response resources have a persistence of 1 year

Summary - Provincial Progress

Table P3: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	215.7	136.4	135.7	128.9
2012				
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				**128.9**
2014 Annual CDM Capacity Target				**1,330**
Verified Peak Demand Savings Target Achieved - 2011 (%):				**9.69%**

Table P4: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	605.5	601.6	599.6	580.9	2,388
2012					0
2013					0
2014					0
Verified Net Cumulative Energy Savings 2011-2014:					**2,388**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Energy Target Achieved - 2011 (%):					**39.79%**

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)

Building Type	Sector
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Exhibit	Tab	Schedule	Appendix	Contents
5 – Cost of Capital and Rate of Return				
	1	1		Overview
		2		Capital Structure Deemed & Actual

OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2013 test years.

Capital Structure:

SLHI has a current deemed capital structure of 4% short term debt with a return of 4.47%, 56% long-term debt with a return of 6.1%, and 40% equity with a return of 8.57% as approved in the 2008 rate decision (EB-2007-0785).

SLHI has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 3.44%, 4% Short Term Debt with a return of 2.08%, and 40% Equity with a return of 9.12%.

Return on Equity:

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.

<u>COST OF DEBT:</u>

Long Term Debt

SLHI is requesting a return on Long Term Debt for the 2013 Test Year of 3.44%. SLHI is currently paying rates varying from 3.00 to 4.70% on existing Long Term Loans negotiated with CIBC Bank. In 2008 SLHI held a capital loan with the CIBC with a principle amount owing of $2.7M. This loan was originally incurred at $2.1M to purchase assets from the former Ontario Hydro in 1998. In 2007, SLHI incurred an additional 1.2M in order to restructure debt and provide a lump sum payment to the Shareholder, the Municipality of Sioux Lookout. The loan is a non-revolving Demand installment loan, with a monthly principle payment of $15,500 plus accrued interest at prime. In 2009, SLHI attempted to obtain financing from Infrastructure Ontario for the Smart Meter initiative but the application was denied. A loan for $738,000 was subsequently incurred from the CIBC with an interest rate of 4.70%, in order to purchase and install Smart Meters. The interest rate is fixed until 2019, at which time there will be 60 months amortization remaining on the loan.

SLHI plans to finance capital projects over the next four years internally, and will therefore not be incurring any additional debt.

Short Term Debt

SLHI is requesting a return on Short Term Debt for the 2013 Test year of 2.08% 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 return on short term debt for 2013 rates based on January 2013 market interest rate information. SLHI's use of a Return on Short Term Debt of 2.08% is without prejudice to any revised Short Term Debt rate that may be adopted by the OEB in early 2013.

Rate Base and Rate of Return

Table 5.1 of Exhibit 5, Tab 1, Schedule 2 details SLHI's rate base, deemed debt/equity ratios, deemed rate of return, actual debt/equity ratios and actual rates of returns for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, and 2012 Bridge and 2013 Test Year Forecast.

CAPITAL STRUCTURE

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	3,290,187	56.00%	3.43%	112,854
Unfunded Short Term Debt	235,013	4.00%	2.07%	4,865
Total Debt	3,525,200	60.00%		117,719
Common Share Equity	2,350,133	40.00%	8.57%	201,406
Total equity	2,350,133	40.00%		201,406
Total Rate Base	5,875,333	100.00%	5.43%	319,126

Deemed Capital Structure for 2013

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,419,699	56.00%	3.44%	117,692
Unfunded Short Term Debt	244,264	4.00%	2.08%	5,081
Total Debt	3,663,963	60.00%		122,772
Common Share Equity	2,442,642	40.00%	9.12%	222,769
Total equity	2,442,642	40.00%		222,769
Total Rate Base	6,106,606	100.00%	5.66%	345,541

1

2 **Table 5.2 – Capital Structure Rate Base Calculations**

2008 Board Approved		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	49.30%	6.10%
Short-Tern Debt	4.00%	4.47%
Return On Equity	46.70%	8.57%
Weighted Debt Rate		5.98%
Regulated Rate of Return		7.19%

WORKING CAPITAL ALLOWANCE FOR 2008		
Distribution Expenses		**$**
Distribution Expenses - Operation		421,827
Distribution Expenses - Maintenance		87,281
Billing and Collecting		349,826
Community Relations		-
Administrative and General Expenses		260,892
Taxes Other than Income Taxes		8,700
Total Eligible Distribution Expenses		**1,128,526**
Power Supply Expenses		8,438,014
Total Working Capital Expenses		9,566,540
Working Capital Allowance @	15.00%	1,434,981

RATE BASE CALCULATION FOR 2008 Board Approved	
Fixed Assets Opening Balance 2008	4,771,410
Fixed Assets Closing Balance 2008	4,783,137
Average Fixed Asset Balance for 2008	4,777,274
Working Capital Allowance	1,434,981
Rate Base	6,212,255
Regulated Rate of Return	7.19%
Regulated Return on Capital	446,555
Deemed Interest Expense	197,929
Deemed Return on Equity	248,626

1 **Table 5.2 - Capital Structure Rate Base Calculations (CONTINUED)**

2008

Description	Deemed Portion	Effective Rate
Long-Term Debt	49.30%	4.73%
Short-Tern Debt	4.00%	4.47%
Return On Equity	46.70%	8.57%
Weighted Debt Rate		4.71%
Regulated Rate of Return		6.51%

2009

Description	Deemed Portion	Effective Rate
Long-Term Debt	52.70%	2.93%
Short-Tern Debt	4.00%	4.47%
Return On Equity	43.30%	8.57%
Weighted Debt Rate		3.04%
Regulated Rate of Return		5.43%

WORKING CAPITAL ALLOWANCE FOR 2008

Distribution Expenses		$
Distribution Expenses - Operation		426,324
Distribution Expenses - Maintenance		91,130
Billing and Collecting		365,700
Community Relations		-
Administrative and General Expenses		263,826
Taxes Other than Income Taxes		-
Total Eligible Distribution Expenses		**1,146,980**
Power Supply Expenses		5,560,391
Total Working Capital Expenses		6,707,371
Working Capital Allowance @	15.00%	1,006,106

WORKING CAPITAL ALLOWANCE FOR 2009

Distribution Expenses		$
Distribution Expenses - Operation		396,303
Distribution Expenses - Maintenance		94,702
Billing and Collecting		381,340
Community Relations		-
Administrative and General Expenses		267,718
Taxes Other than Income Taxes		-
Total Eligible Distribution Expenses		**1,140,062**
Power Supply Expenses		3,497,912
Total Working Capital Expenses		4,637,974
Working Capital Allowance @	15.00%	695,696

RATE BASE CALCULATION FOR 2008

Fixed Assets Opening Balance 2008	4,604,504
Fixed Assets Closing Balance 2008	4,626,547
Average Fixed Asset Balance for 2008	4,615,526
Working Capital Allowance	1,006,106
Rate Base	5,621,631
Regulated Rate of Return	6.51%
Regulated Return on Capital	366,130
Deemed Interest Expense	141,142
Deemed Return on Equity	224,988

RATE BASE CALCULATION FOR 2009

Fixed Assets Opening Balance 2009	4,626,547
Fixed Assets Closing Balance 2009	4,567,167
Average Fixed Asset Balance for 2008	4,596,857
Working Capital Allowance	695,696
Rate Base	5,292,553
Regulated Rate of Return	5.43%
Regulated Return on Capital	287,590
Deemed Interest Expense	91,194
Deemed Return on Equity	196,397

1 **Table 5.2 – Capital Structure Rate Base Calculations (CONTINUED)**

2010			2011		
Description	**Deemed Portion**	**Effective Rate**	**Description**	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	3.10%	Long-Term Debt	56.00%	3.42%
Short-Tern Debt	4.00%	4.47%	Short-Tern Debt	4.00%	4.47%
Return On Equity	40.00%	8.57%	Return On Equity	40.00%	8.57%
Weighted Debt Rate		3.20%	**Weighted Debt Rate**		3.49%
Regulated Rate of Return		5.35%	**Regulated Rate of Return**		5.52%

WORKING CAPITAL ALLOWANCE FOR 2010			WORKING CAPITAL ALLOWANCE FOR 2011		
Distribution Expenses			**Distribution Expenses**		
Distribution Expenses - Operation		493,191	Distribution Expenses - Operation		479,052
Distribution Expenses - Maintenance		116,678	Distribution Expenses - Maintenance		106,053
Billing and Collecting		310,460	Billing and Collecting		265,561
Community Relations		-	Community Relations		-
Administrative and General Expenses		240,621	Administrative and General Expenses		302,369
Taxes Other than Income Taxes		-	Taxes Other than Income Taxes		-
Total Eligible Distribution Expenses		**1,160,949**	**Total Eligible Distribution Expenses**		**1,153,035**
Power Supply Expenses		5,202,375	Power Supply Expenses		6,153,109
Total Working Capital Expenses		6,363,324	**Total Working Capital Expenses**		7,306,144
Working Capital Allowance @	15.00%	954,499	Working Capital Allowance @	15.00%	1,095,922

RATE BASE CALCULATION FOR 2010		RATE BASE CALCULATION FOR 2011	
Fixed Assets Opening Balance 2010	4,567,167	Fixed Assets Opening Balance 2011	4,525,711
Fixed Assets Closing Balance 2010	4,525,711	Fixed Assets Closing Balance 2011	4,465,524
Average Fixed Asset Balance for 2009	4,546,439	**Average Fixed Asset Balance for 2010**	4,495,618
Working Capital Allowance	954,499	Working Capital Allowance	1,095,922
Rate Base	5,500,938	**Rate Base**	5,591,539
Regulated Rate of Return	5.35%	Regulated Rate of Return	5.52%
Regulated Return on Capital	294,042	**Regulated Return on Capital**	308,725
Deemed Interest Expense	105,469	Deemed Interest Expense	117,047
Deemed Return on Equity	188,572	Deemed Return on Equity	191,678

1 **Table 5.2 – Capital Structure Rate Base Calculations (CONTINUED)**

2012

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	3.43%
Short-Tern Debt	4.00%	2.07%
Return On Equity	40.00%	8.57%
Weighted Debt Rate		3.34%
Regulated Rate of Return		5.43%

2013

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	3.44%
Short-Tern Debt	4.00%	2.08%
Return On Equity	40.00%	9.12%
Weighted Debt Rate		3.35%
Regulated Rate of Return		5.66%

WORKING CAPITAL ALLOWANCE FOR 2012

Distribution Expenses		
Distribution Expenses - Operation		584,640
Distribution Expenses - Maintenance		320,616
Billing and Collecting		298,102
Community Relations		-
Administrative and General Expenses		389,675
Taxes Other than Income Taxes		4,986
Total Eligible Distribution Expenses		**1,598,019**
Power Supply Expenses		7,558,782
Total Working Capital Expenses		9,156,801
Working Capital Allowance @	13.00%	1,190,384

WORKING CAPITAL ALLOWANCE FOR 2013

Distribution Expenses		
Distribution Expenses - Operation		628,363
Distribution Expenses - Maintenance		196,645
Billing and Collecting		316,965
Community Relations		-
Administrative and General Expenses		407,460
Taxes Other than Income Taxes		4,986
Total Eligible Distribution Expenses		**1,554,419**
Power Supply Expenses		7,802,913
Total Working Capital Expenses		9,357,332
Working Capital Allowance @	13.00%	1,216,453

RATE BASE CALCULATION FOR 2012

Fixed Assets Opening Balance 2012	4,465,524
Fixed Assets Closing Balance 2012	4,904,374
Average Fixed Asset Balance for 2011	4,684,949
Working Capital Allowance	1,190,384
Rate Base	5,875,333
Regulated Rate of Return	5.43%
Regulated Return on Capital	319,126
Deemed Interest Expense	117,719
Deemed Return on Equity	201,406

RATE BASE CALCULATION FOR 2013

Fixed Assets Opening Balance 2013	4,904,374
Fixed Assets Closing Balance 2013	4,875,931
Average Fixed Asset Balance for 2012	4,890,153
Working Capital Allowance	1,216,453
Rate Base	6,106,606
Regulated Rate of Return	5.66%
Regulated Return on Capital	345,541
Deemed Interest Expense	122,772
Deemed Return on Equity	222,769

1 # Table 5.3 – Actual Weighted Average Cost of Long-Term Debt

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
CIBC Bank Loan	CIBC	n		2,688,989	15	4.73%	2008	127,189
CIBC Smart Meter Bank Loan	CIBC	n		0			2008	0
CIBC Bank Loan	CIBC	n		2,502,989	15	2.40%	2009	60,072
CIBC Smart Meter Bank Loan	CIBC	n		750,000	15	4.70%	2009	35,250
CIBC Bank Loan	CIBC	n		2,316,989	15	2.60%	2010	60,242
CIBC Smart Meter Bank Loan	CIBC	n		732,569	15	4.70%	2010	34,431
CIBC Bank Loan	CIBC	n		2,130,989	15	3.00%	2011	63,930
CIBC Smart Meter Bank Loan	CIBC	n		696,455	15	4.70%	2011	32,733
CIBC Bank Loan	CIBC	n		1,944,989	15	3.00%	2012	58,350
CIBC Smart Meter Bank Loan	CIBC	n		658,607	15	4.70%	2012	30,955
CIBC Bank Loan	CIBC	n		1,763,851	15	3.00%	2013	52,916
CIBC Smart Meter Bank Loan	CIBC	n		618,942	15	4.70%	2013	29,090
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0
								0

2008 Total Long Term Debt	2,688,989	**Total Interest Cost for 2008**	127,189
		Weighted Debt Cost Rate for 2008	4.73%
2009 Total Long Term Debt	3,252,989	**Total Interest Cost for 2009**	95,322
		Weighted Debt Cost Rate for 2009	2.93%
2010 Total Long Term Debt	3,049,558	**Total Interest Cost for 2010**	94,672
		Weighted Debt Cost Rate for 2010	3.10%
2011 Total Long Term Debt	2,827,444	**Total Interest Cost for 2011**	96,663
		Weighted Debt Cost Rate for 2011	3.42%
2012 Total Long Term Debt	2,603,596	**Total Interest Cost for 2012**	89,304
		Weighted Debt Cost Rate for 2012	3.43%
2013 Total Long Term Debt	2,382,793	**Total Interest Cost for 2013**	82,006
		Weighted Debt Cost Rate for 2013	3.44%

Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency or Surplus				
	1	1		Revenue Deficiency - Overview
		2		Cost Drivers for Revenue Deficiency

REVENUE DEFICIENCY - OVERVIEW

Sioux Lookout Hydro Inc.'s net revenue deficiency is $173,089 when grossed up for PILs. This deficiency is calculated as the difference between the 2013 Test Year Revenue Requirement of $2,091,430 and the Forecast 2013 Test Year Revenue, based on the 2012 approved rates, at $1,918,341. Table 6.1 on the following page provides the revenue deficiency calculations.

Revenue Requirement:

SLHI's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILS'
- Deemed Interest & Return on Equity

SLHI's revenue requirement is primarily received through electricity distribution rates and offset by revenue from OEB-approved specific service charges, late payment charges, interest, and other operating income.

Table 6.1 Revenue Deficiency

Sioux Lookout Hydro Inc.
Revenue Deficiency Determination

Description	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue		
Revenue Deficiency		**173,089**
Distribution Revenue	1,789,316	1,789,316
Other Operating Revenue (Net)	129,025	129,025
Total Revenue	**1,918,341**	**2,091,430**
Costs and Expenses		
Administrative & General, Billing & Collecting	724,425	724,425
Operation & Maintenance	825,008	825,008
Depreciation & Amortization	180,404	180,404
Property Taxes	4,986	4,986
Deemed Interest	122,772	122,772
Total Costs and Expenses	**1,857,595**	**1,857,595**
Utility Income Before Income Taxes	**60,746**	**233,834**
Income Taxes:		
Corporate Income Taxes	-15,763	11,066
Total Income Taxes	**-15,763**	**11,066**
Utility Net Income	**76,509**	**222,769**
Income Tax Expense Calculation:		
Accounting Income	60,746	233,834
Tax Adjustments to Accounting Income	-162,444	-162,444
Taxable Income	**-101,698**	**71,390**
Income Tax Expense	**-15,763**	11,066
Tax Rate Refecting Tax Credits	15.50%	15.50%
Actual Return on Rate Base:		
Rate Base	6,106,606	6,106,606
Interest Expense	122,772	122,772
Net Income	76,509	222,769
Total Actual Return on Rate Base	**199,281**	**345,541**
Actual Return on Rate Base	3.26%	5.66%
Required Return on Rate Base:		
Rate Base	6,106,606	6,106,606
Return Rates:		
Return on Debt (Weighted)	3.35%	3.35%
Return on Equity	9.12%	9.12%
Deemed Interest Expense	122,772	122,772
Return On Equity	222,769	222,769
Total Return	**345,541**	**345,541**
Expected Return on Rate Base	5.66%	5.66%
Revenue Deficiency After Tax	**146,260**	**-0**
Revenue Deficiency Before Tax	**173,089**	**-0**

COST DRIVERS ON REVENUE DEFICIENCY

The Applicant notes there are several factors that contribute to the gross revenue deficiency of $173,089 for the 2013 Test Year. The following discussion highlights some significant items that contribute to this deficiency.

Operating Expenses

SLHI's OM&A expenses have increased from the 2008 approved amount of $1,119,826 to $1,554,393 in the 2013 Test Year. SLHI has made changes to its capitalization policy in order to be compliant with the new standards. Under MCGAAP $39,127of expenses that SLHI previously capitalized will no longer be capitalized. The full details of this change are outlined in Exhibit 4, Tab 2 and Exhibit 4 Tab 4. The remaining cost increases of $395,440 over the 4 year period are discussed in Exhibit 4, Tab 2.

Rate Base

In this application SLHI is applying for a rate base of $6,106,606 compared to a rate base of $6,212,254 which was approved during SLHI's 2008 cost of service application. The decrease is a result of a combination of lower than budgeted actual capital expenditures in 2007 and 2008 and the lower working capital allowance. The working capital allowance has decreased by $218,528 from the 2008 Board Approved amount due to in part to the change from 15% working capital allowance to the current approved 13%. The additional amount can be attributed to the decrease in cost of power expenses from the 2008 Board Approved amount offset by increased OM&A costs. The changes due to MCGAAP, working capital and capital spending have been fully disclosed in Exhibit 2 of this application.

The changes in the deemed debt to equity ratio from 53/47 to 60/40 along with reduced interest rates have resulted in decreased deemed interest expense by $75,157. Also, the increase in deemed return on equity from 8.57% to 9.12% is offset by the decreased rate base resulting in the deemed return on equity to decrease by $25,857.

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation		1		Cost Allocation Overview
		2		Summary of Results and Proposed Changes
			7-A	2013 Updated Cost Allocation Study

COST ALLOCATION OVERVIEW

Introduction:

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. SLHI prepared a cost allocation information filing consistent with SLHI's understanding of the Directions, the Guidelines, the Model and the Instructions. SLHI submitted this filing to the OEB on May 15, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

In SLHI's 2008 EDR Cost of Service Application (EB-2007-0785), the results of the original cost allocation study filed on May 15, 2007 was used as a basis for SLHI to propose reallocations of distribution costs across customer classes to address the issue of cross-subsidization. In their decision dated September 11, 2008, the Board required SLHI to move the revenue to cost ratio to the lower end of the target range which was 70% in equal increments over three years for the Street Lighting rate class. The reallocations were based on the objective of moving the revenue to cost ratios to be within the Board's acceptable range as outlined in the "Report on Application of Cost Allocation for Electricity Distributors" (the Cost Allocation Report") issued by the OEB on November 28, 2007.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released the new Cost Allocation model and instructed 2012 Cost of Service filers to use the revised model in their applications. On June 28, 2012, the Board released a revised Cost Allocation model to be used by 2013 Cost of Service filers in their applications.

In the March 31st Board Report, the Board stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

For the purposes of this Application, SLHI has used the 2013 version of the cost allocation model and submitted the revised cost allocation study to reflect 2013 test year costs, customer numbers and demand values. The 2013 demand values are based on the weather normalized load forecast used to design rates. SLHI has developed weighting factors as outlined below based on discussions with staff experienced in the subject area.

Services (Account 1855)

Rate Class	Services Weighting Factor
Residential	1
General Service < 50kW	1.1
General Service ≥ 50 kW	16.7
All other classes	N/A

Billing and Collection (Accounts 5315 – 5340, except 5335)

Rate Class	Billing Weighting Factor
Residential	1
General Service < 50kW	1
General Service ≥ 50 kW	5.9
Street Lighting	20.6
Unmetered Scattered Load	1.4

Meter Capital (Sheet I7.1)

Meter Type	Installation Cost per Meter
Smart Meter – Residential	$136.69
Smart Meter – General Service GS < 50 kW	$154.51
Demand with IT and Interval Capability – Secondary	$2,300
Demand with IT and Interval Capability - Primary	$4,600

Meter Reading (Sheet I7.2)

Meter Type	Meter Reading Weighting
Smart Meter – Residential	1
Smart Meter – General Service < 50 kW	1
General Service > 50 kW	50.43
General Service > 50 kW – Interval	750

SUMMARY OF RESULTS AND PROPOSED CHANGES

The data used in the updated cost allocation study is consistent with SLHI's cost data that supports the proposed 2013 revenue requirement outlined in this application. Consistent with the Guidelines, SLHI's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to SLHI, its engineering records, and its customer and financial information systems. The cost allocation study has been included in Appendix 7-A.

Capital contributions, depreciation and accumulated depreciation by USoA is consistent with the information provided in the 2013 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2013 customer forecast outlined in Exhibit 3. The load profiles for all other rate class are the same as those used in the original information filing but have been scaled to match the load forecast. The following outlines the scaling factors used by rate class.

Table 7-1: Load Profile Scaling Percentages

Rate Class	2004 Weather Normal Values used in Informational Filing (kWh)	2013 Weather Normal Values (kWh)	Scaling Factor
Residential	36,147,605	34,980,266	96.8%
GS < 50 kW	17,712,066	12,526,981	70.7%
GS 50 to 4,999 kW	44,407,976	25,251,296	56.9%
Street Lighting	489,355	499,759	102.1%
Unmetered Scattered Load	40,915	11,962	29.2%
Total	**98,797,917**	**73,270,264**	**74.2%**

The allocated cost by rate class for the 2007 information filing and 2013 updated study are provided in the following Table 7-2.

Table 7.2: Allocated Cost - (Consistent with Appendix 2-P: Allocated Costs)				
Rate Class	**Cost Allocated in Original Cost Allocation Information Filing**	**%**	**Cost Allocated in the 2013 Study**	**%**
Residential	951,703	58.7%	1,355,777	64.8%
GS < 50 kW	318,511	19.7%	298,118	14.3%
GS 50 to 4,999 kW	226,666	14.0%	288,811	13.8%
Street Lighting	120,731	7.4%	147,819	7.1%
Unmetered Scattered Load	3,002	0.2%	905	0.0%
Total	**1,620,613**	**100.0%**	**2,091,430**	**100.0%**

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the Report of the Board on Cost Allocation released in relation to EB-2010-0219, dated March 31, 2011, the Board established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7-3 below. In addition Table 7-3 provides SLHI's revenue to cost ratios from the approved 2010 IRM application, EB-2009-0249; the updated 2013 cost allocation study and the proposed 2013 to 2015 ratios. Information from the 2010 IRM application has been included as this was the last year of a three year program to move the revenue to cost ratio for the Street Lighting rate class to 70%.

Table 7-3: Revenue to Cost Ratios - (Consistent with Appendix 2-P: Revenue to Cost Ratios)

Class	2010 IRM Application	2013 Updated Cost Allocation Study	2013 Proposed Rates	2014 Proposed Rates	2015 Proposed Rates	Board Targets Min to Max	
Residential	98.09%	90.31%	96.36%	96.36%	96.36%	85.00%	115.00%
GS < 50	96.26%	115.16%	109.87%	109.87%	109.87%	80.00%	120.00%
GS 50 to 4,999 kW	129.16%	138.60%	119.85%	119.85%	119.85%	80.00%	120.00%
Street Lighting	70.00%	83.00%	74.91%	74.91%	74.91%	70.00%	120.00%
Unmetered Scattered Load	98.29%	81.01%	80.93%	80.93%	80.93%	80.00%	120.00%

SLHI is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes calculated by the 2013 updated cost allocation study in order to be within the Board's target range. The GS 50 to 4,999 kW Class revenue to cost ratio exceeded the Board Target Maximum, therefore in order to decrease this to the higher end of the target at 120%, the Residential class was increased and the GS < 50 kW class was decreased in order to move these ratios closer to 100%. The Street Lighting Class was decreased to 75% and the Unmetered Scattered Load class was decreased slightly in order to reduce the rate impacts to these classes as well as keep the ratio within the Board Minimum and Maximum targets.

The following table 7-4 provides information on calculated class revenue. The resulting 2013 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

1

Table 7-4: Calculated Class Revenue - (Consistent with Appendix 2-P: Calculated Class Revenues)

Class	2013 Base Revenue at Existing Rates	2013 Proposed Base Revenue Allocated at Existing Rates Proportion	2013 Proposed Base Revenue	Miscellaneous Revenue
Residential	$1,040,067	$1,140,677	$1,222,636	$83,767
GS < 50 kW	$296,199	$324,852	$309,069	$18,447
GS 50 to 4,999 kW	$350,336	$384,225	$330,062	$16,078
Street Lighting	$102,100	$111,976	$100,028	$10,675
Unmetered Scattered Load	$615	$675	$674	$58
Total	**$1,789,317**	**$1,962,405**	**$1,962,470**	**$129,025**

The $65 difference in the Proposed Base Revenue compared to the Proposed Base Revenue Allocated at Existing Rates is due to rounding.

Appendix 7-A

2013 Updated Cost Allocation Study

Sheet I6.1 Revenue Worksheet - First Run

Total kWhs from Load Forecast	73,270,262
Total kWs from Load Forecast	65,213
Deficiency from RRWF	- 173,089
Miscellaneous Revenue	129,025

	ID	Total	1 Residential	2 GS <50	3 GS 50 to 4,999	7 Street Light	9 Unmetered Scattered Load
Billing Data							
Forecast kWh	CEN	73,270,262	34,980,266	12,526,981	25,251,296	499,759	11,962
Forecast kW	CDEM	65,213			63,706	1,507	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		15,584			15,584		
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	76,087,944	36,651,481	13,125,469	25,803,780	495,358	11,856
kWh - 30 year weather normalized amount	Click here to Enter Data	67,238,930	32,100,822	11,495,807	23,172,704	458,620	10,977
Existing Monthly Charge			$24.26	$43.11	$398.88	$9.87	$21.50
Existing Distribution kWh Rate			$0.0104	$0.0082			$0.0083
Existing Distribution kW Rate					$1.3832	$26.0218	
Existing TFOA Rate					$0.37		
Additional Charges							
Distribution Revenue from Rates		$1,795,146	$1,040,067	$296,199	$356,165	$102,100	$615
Transformer Ownership Allowance		$5,830	$0	$0	$5,830	$0	$0
Net Class Revenue	CREV	$1,789,316	$1,040,067	$296,199	$350,336	$102,100	$615
Data Mismatch Analysis							
Revenue with 30 year weather normalized kWh		1,642,026	954,452	271,817	321,497	93,695	565

Weather Normalized Data from Hydro One

	Total	Residential	GS <50	GS 50 to 4,999	Street Light	Unmetered Scattered Load
kWh - 30 year weather normalized amount	73,270,262	34,980,266	12,526,981	25,251,296	499,759	11,962
Loss Factor		1.0897	1.0897	1.0897	1.0897	1.0897

Sheet I6.2 Customer Data Worksheet - First Run

			1	2	3	7	9
	ID	Total	Residential	GS <50	GS 50 to 4,999	Street Light	Unmetered Scattered Load
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$17,624	$15,025	$1,784	$816	$0	$0
Late Payment 3 Year Historical Average	LPHA	$0					
Number of Bills	CNB	33,084	27,876	4,488.00	672	24	24
Number of Devices			2,323	374	56	531	2
Number of Connections (Unmetered)	CCON	533				531	2
Total Number of Customers	CCA	2,757	2,323	374	56	2	2
Bulk Customer Base	CCB	-					
Primary Customer Base	CCP	2,757	2,323	374	56	2	2
Line Transformer Customer Base	CCLT	2,752	2,323	374	51	2	2
Secondary Customer Base	CCS	2,752	2,323	374	51	2	2
Weighted - Services	CWCS	3,598	2,323	423	853	-	-
Weighted Meter -Capital	CWMC	515,618	317,531	57,787	140,300	-	-
Weighted Meter Reading	CWMR	72,227	27,876	4,488	39,863	-	-
Weighted Bills	CWNB	36,841	27,876	4,488	3,951	493	33

Bad Debt Data

Historic Year:	2010	22,877	20,091	339	2,448		
Historic Year:	2011	9,996	4,983	5,013			
Historic Year:	2012	20,000	20,000				
Three-year average		**17,624**	**15,025**	**1,784**	**816**	**-**	**-**

Sheet I8 Demand Data Worksheet - First Run

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

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

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

			1	2	3	7	9
Customer Classes		Total	Residential	GS <50	GS 50 to 4,999	Street Light	Unmetered Scattered Load
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	-					
Bulk Delivery CP	BCP1	-					
Total Sytem CP	DCP1	15,338	6,981	3,520	4,707	129	1
4 CP							
Transformation CP	TCP4	-					
Bulk Delivery CP	BCP4	-					
Total Sytem CP	DCP4	59,008	31,587	10,596	16,563	257	5
12 CP							
Transformation CP	TCP12	-					
Bulk Delivery CP	BCP12	-					
Total Sytem CP	DCP12	141,566	73,644	26,806	40,714	386	16
NON CO_INCIDENT PEAK							
1 NCP							
Classification NCP from Load Data Provider	DNCP1	17,748	9,138	3,773	4,707	129	1
Primary NCP	PNCP1	17,748	9,138	3,773	4,707	129	1
Line Transformer NCP	LTNCP1	17,748	9,138	3,773	4,707	129	1
Secondary NCP	SNCP1	17,748	9,138	3,773	4,707	129	1
4 NCP							
Classification NCP from Load Data Provider	DNCP4	65,218	33,371	13,316	18,011	515	5
Primary NCP	PNCP4	65,218	33,371	13,316	18,011	515	5
Line Transformer NCP	LTNCP4	65,218	33,371	13,316	18,011	515	5
Secondary NCP	SNCP4	65,218	33,371	13,316	18,011	515	5
12 NCP							
Classification NCP from Load Data Provider	DNCP12	156,358	78,074	29,703	47,021	1,544	16
Primary NCP	PNCP12	156,358	78,074	29,703	47,021	1,544	16
Line Transformer NCP	LTNCP12	156,358	78,074	29,703	47,021	1,544	16
Secondary NCP	SNCP12	156,358	78,074	29,703	47,021	1,544	16

Sheet O1 Revenue to Cost Summary Worksheet - First Run

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS 50 to 4,999	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$1,789,316	$1,040,067	$296,199	$350,336	$102,100	$615
mi	Miscellaneous Revenue (mi)	$129,025	$83,726	$18,460	$16,073	$10,708	$58
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	$1,918,341	$1,123,793	$314,658	$366,408	$112,808	$673
	Factor required to recover deficiency (1 + D)	1.0967					
	Distribution Revenue at Status Quo Rates	$1,962,405	$1,140,677	$324,852	$384,225	$111,976	$675
	Miscellaneous Revenue (mi)	$129,025	$83,726	$18,460	$16,073	$10,708	$58
	Total Revenue at Status Quo Rates	$2,091,430	$1,224,404	$343,311	$400,298	$122,684	$733
	Expenses						
di	Distribution Costs (di)	$752,067	$466,894	$114,825	$97,441	$72,625	$283
cu	Customer Related Costs (cu)	$389,906	$284,859	$46,084	$54,792	$3,910	$261
ad	General and Administration (ad)	$412,446	$270,645	$58,294	$55,259	$28,056	$193
dep	Depreciation and Amortization (dep)	$180,404	$111,494	$25,823	$30,223	$12,814	$50
INPUT	PILs (INPUT)	$11,066	$6,885	$1,647	$1,586	$944	$4
INT	Interest	$122,772	$76,391	$18,278	$17,591	$10,471	$41
	Total Expenses	$1,868,661	$1,217,167	$264,952	$256,892	$128,819	$830
	Direct Allocation	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$222,769	$138,610	$33,166	$31,919	$19,000	$74
	Revenue Requirement (includes NI)	$2,091,430	$1,355,777	$298,118	$288,811	$147,819	$905
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$8,535,027	$5,300,451	$1,271,964	$1,226,006	$733,747	$2,860
gp	General Plant - Gross	$955,255	$594,083	$141,605	$138,890	$80,364	$313
accum dep	Accumulated Depreciation	($3,570,940)	($2,213,686)	($537,056)	($501,098)	($317,860)	($1,240)
co	Capital Contribution	($1,029,191)	($638,183)	($148,599)	($162,685)	($79,415)	($309)
	Total Net Plant	$4,890,151	$3,042,664	$727,913	$701,113	$416,835	$1,625
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$7,802,913	$3,755,058	$1,344,745	$2,650,828	$51,060	$1,222
	OM&A Expenses	$1,554,419	$1,022,397	$219,203	$207,492	$104,591	$736
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	*$9,357,332*	*$4,777,456*	*$1,563,948*	*$2,858,319*	*$155,651*	*$1,958*
	Working Capital	$1,216,453	$621,069	$203,313	$371,582	$20,235	$255
	Total Rate Base	$6,106,604	$3,663,733	$931,227	$1,072,695	$437,070	$1,879
		Rate Base Input equals Output					

Equity Component of Rate Base	**$2,442,642**	**$1,465,493**	**$372,491**	**$429,078**	**$174,828**	**$752**
Net Income on Allocated Assets	**$222,769**	**$7,236**	**$78,359**	**$143,406**	**($6,135)**	**($98)**
Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	**$222,769**	**$7,236**	**$78,359**	**$143,406**	**($6,135)**	**($98)**
RATIOS ANALYSIS						
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**90.31%**	**115.16%**	**138.60%**	**83.00%**	**81.03%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**($173,089)**	($231,984)	$16,540	$77,597	($35,011)	($231)
	Deficiency Input equals Output					
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**$0**	($131,374)	$45,193	$111,487	($25,135)	($172)
RETURN ON EQUITY COMPONENT OF RATE BASE	9.12%	0.49%	21.04%	33.42%	-3.51%	-12.97%

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

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	9
	Residential	GS <50	GS 50 to 4,999	Street Light	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$9.83	$9.89	$93.65	$0.19	$10.08
Customer Unit Cost per month - Directly Related	$13.32	$13.47	$123.19	$0.42	$13.93
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$35.33	$35.00	$150.03	$22.60	$34.36
Existing Approved Fixed Charge	$24.26	$43.11	$398.88	$9.87	$21.50

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	7	9
	Total	Residential	GS <50	GS 50 to 4,999	Street Light	Unmetered Scattered Load
General Plant - Gross Assets	$955,255	$594,083	$141,605	$138,890	$80,364	$313
General Plant - Accumulated Depreciation	($751,648)	($467,458)	($111,423)	($109,287)	($63,235)	($246)
General Plant - Net Fixed Assets	$203,607	$126,625	$30,182	$29,604	$17,129	$67
General Plant - Depreciation	$27,288	$16,971	$4,045	$3,968	$2,296	$9
Total Net Fixed Assets Excluding General Plant	$4,686,544	$2,916,039	$697,731	$671,510	$399,706	$1,558
Total Administration and General Expense	$412,446	$270,645	$58,294	$55,259	$28,056	$193
Total O&M	$1,141,973	$751,753	$160,909	$152,232	$76,535	$543

Exhibit	Schedule	Appendix	Contents
8 – Rate Design			
	1		Rate Design Overview
	2		Rate Mitigation
	3		Existing Rate Classes
	4		Existing Rate Schedule
	5		Proposed Rate Classes and Specific Service Charges
	6		Proposed Rates and Charges
	7		Reconciliation of Rate Class Revenue
	8		Rate and Bill Impacts
		8-A	Existing Rate Schedule
		8-B	Bill Impacts

RATE DESIGN OVERVIEW

This Exhibit documents the calculation of SLHI's proposed distribution rates by rate class for the 2013 test year, based on the rate design as proposed in this Exhibit.

SLHI has determined its total 2013 service revenue requirement to be $2,091,430. The total revenue offsets in the amount of $129,025 reduce SLHI's total service revenue requirement to a base revenue requirement to $1,962,405 which is used to determine the proposed distribution rates. The base revenue requirement is derived from SLHI's 2013 capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in the table below:

Table 8.1: Calculation of Base Revenue Requirement	
Description	**Amount**
OM&A Expenses	1,554,419
Amortization Expenses	180,404
Total Distribution Expenses	
Regulated Return On Capital	345,541
PILs	11,066
Service Revenue Requirement	**2,091,430**
Less: Revenue Offsets	129,025
Base Revenue Requirement	**1,962,405**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. The following table shows how the base revenue requirement has been allocated to the rate classes.

Table 8.2: Rate Class Base Revenue Requirement	
Rate Class	**2013 Base Revenue Requirement**
Residential	$1,222,636
General Service < 50 kW	309,069
General Service 50 to 4,999 kW	330,062
Street Lighting	100,028
Unmetered Scattered Loads	674
Total	**$1,962,470**

Note: small difference is due to rounding.

Determination of Monthly Fixed Charges:

Based on applying the existing approved monthly service charges, excluding the smart meter adder, to the forecasted number of customers for 2013 and applying the existing approved distribution volumetric charge, excluding the adjustment for LV and transformation allowance, to 2013 forecasted volumes the following table outlines the SLHI's current split between fixed and variable distribution revenue.

Table 8.3: Current Fixed/Variable Split					
Rate Class	**2013 Fixed Base Revenue with 2012 Approved Rates**	**2013 Variable Base Revenue with 2012 Approved Rates**	**2013 Total Base Revenue with 2012 Approved Rates**	**Fixed Revenue Portion**	**Variable Revenue Portion**
Residential	676,272	363,795	1,040,067	65.0%	35.0%
General Service < 50 kW	193,478	102,721	296,199	65.3%	34.7%
General Service 50 to 4,999 kW	268,047	88,118	356,165	75.3%	24.7%
Street Lighting	62,892	39,208	102,100	61.6%	38.4%
Unmetered Scattered Loads	516	99	615	83.9%	16.1%
Total	**1,201,205**	**593,941**	**1,795,146**	**66.9%**	**33.1%**

SLHI submits that it is appropriate for 2013 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, the OEB addressed a number of “Other Rate Matters”, including the treatment of the fixed rate component (the Monthly Service Charge, or ‘MSC’) of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled “Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors”. SLHI’s MSCs exceed that floor amount by rate class. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB’s Rate Review proceeding (EB-2009-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time. In accordance with the filing requirements the following information has been provided with regards to the MSC.

Table 8.4: Monthly Service Charge Information for Cost Allocation Model

Rate Class	2012 Approved Monthly Service Charge	2013 Proposed Monthly Service Charge	Customer Unit Cost per Month - Avoided Cost	Customer Unit Cost per Month - Minimum System with PLCC Adjustment
Residential	$24.26	$28.52	$9.83	$35.33
General Service < 50 kW	$43.11	$44.98	$9.89	$35.00
General Service 50 to 4,999 kW	$398.88	$375.80	$93.65	$150.03
Street Lighting	$9.87	$9.67	$0.19	$22.60
Unmetered Scattered Loads	$21.50	$23.56	$10.08	$34.36

Consistent with recent Board Decision on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities this Application proposes to maintain the current fixed/variable proportions for all rate classes as shown in the following table.

Table 8.5: Proposed Monthly Service Charge

Rate Class	Total Base Revenue Requirement	Fixed Revenue Portion	Fixed Revenue	Annualized Customer/ Connections	Proposed Fixed Distribution Charge
Residential	$1,222,636	65.022%	$794,982	27,876	$28.52
General Service < 50 kW	$309,069	65.320%	$201,885	4,488	$44.98
General Service 50 to 4,999 kW	$330,062	76.512%	$252,536	672	$375.80
Street Lighting	$100,028	61.598%	$61,616	6,372	$9.67
Unmetered Scattered Loads	$674	83.894%	$565	24	$23.56
Total	$1,962,470	66.833%	$1,311,584		

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2013 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides SLHI's calculations of its proposed variable distribution charges for the 2013 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8.6: Proposed Distribution Volumetric Charge

Rate Class	Total Base Revenue Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW as Required	Unit of Measure	Proposed Variable Distribution Charge Before LV and Transformer Discount
Residential	$1,222,636	$794,982	$427,654	34,980,266	kWh	0.0122
General Service < 50 kW	$309,069	$201,885	$107,185	12,526,981	kWh	0.0086
General Service 50 to 4,999 kW	$330,062	$252,536	$77,526	63,706	kW	1.2169
Street Lighting	$100,028	$61,616	$38,412	1,507	kW	25.4938
Unmetered Scattered Loads	$674	$565	$109	11,962	kWh	0.0091
Total	$1,962,470	$1,311,584	$650,886			

Proposed Adjustment for Transformer Allowance:

Currently, SLHI provides a Transformer Allowance to those customers that own their transformation facilities. SLHI proposes to maintain the current approved transformer ownership allowance of $0.3741 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of the Transformer Allowance expected to be provided to those GS > 50 kW customers that own their transformers is included in the GS > 50 kW volumetric charge. As a result, the proposed volumetric charge of 1.2169 per kW for the GS > 50 kW customer class is increased by $0.0916 per kW to include the amount of the Transformer Allowance in the GS > 50 kW class distribution volumetric rate This means the total proposed distribution volumetric charge for the GS > 50 kW class will be $1.3085

Proposed Distribution Rates:

The following table sets out SLHI's proposed 2013 electricity distribution rates based on the foregoing calculations.

Table 8.7: Proposed 2013 Distribution Rates

Rate Class	Proposed Fixed Distribution Charge	Unit of Measure	Proposed Variable Distribution Charge Including Transformer Allowance Adjustment
Residential	$28.52	kWh	$0.0122
General Service < 50 kW	$44.98	kWh	$0.0086
General Service 50 to 4,999 kW	$375.80	kW	$1.3085
Street Lighting	$9.67	kW	$25.4938
Unmetered Scattered Loads	$23.56	kWh	$0.0091
Transformer Discount		kW	-$0.3741

Recovery of Low Voltage (LV) Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $250,381 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. The amount of forecasted LV costs in 2013 is based on calculations shown in Table 8-8. These calculations are based on applying the appropriate Hydro One sub transmission charges to the forecasted units for 2013. The Hydro One sub transmission charges used in the calculations are from the Hydro One Approved Rate Schedule (EB-2012-0136). The forecasted units for 2013 is based on the trend in the level of sub transmission service (i.e kW) that Hydro One provided to SLHI from 2011 to 2012.

Table 8.8: Low Voltage Costs					
2013 Data for LV Charges					
Number of Monthly Service Charges	2				
Number of Meter Points	2				
HVDS kW	143,728				
Hydro One Sub Transmission Charges based on			**Units**	**Months**	
Service Charge	$295.68	per month	2	12	$7,096
Meter Charge	$471.17	per meter per month	2	12	$11,308
Facility charge for connection to high-voltage (> 13.8 kV secondary)	$1.614	per kW	143,728	12	$231,977
					$250,381
Source of Rates - Hydro One Approved Rate Order December 10,2012, EB-2012-0136, Appendix A, page 21 of 28					

The calculation of proposed LV charges to recover the 2013 LV amount is outlined in the following table:

Table 8.9: Proposed LV Charges

Rate Class	Unit of Measure	Retail Transmission Connection Rate ($) Per kWh or kW	Basis for Allocation ($)	Allocation Percentages	Allocated $	Annualized kwh or kW as required	Proposed LV Charge
Residential	kWh	0.0013	45,474	51.10%	127,954	34,980,266	0.0037
General Service < 50 kW	kWh	0.0011	13,780	15.49%	38,773	12,526,981	0.0031
General Service 50 to 4,999 kW	kW	0.4581	29,184	32.80%	82,116	63,706	1.2890
Street Lighting	kW	0.3542	534	0.60%	1,502	1,507	0.9966
Unmetered Scattered Loads	kWh	0.0011	13	0.01%	37	11,962	0.0031
			88,985	100.00%	250,381		

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "2013_RTSR_Model_V3" and instructions for distributors to complete as part of their 2013 electricity rate applications. SLHI has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.10 is reproduced from the Board model and indicates the new RTSR's**.**

Table 8.10

Final 2013 RTS Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0065	$ 0.0015
General Service Less Than 50 kW	kWh	$ 0.0059	$ 0.0012
General Service 50 to 4,999 kW	kW	$ 2.3598	$ 0.5128
Unmetered Scattered Load	kWh	$ 0.0059	$ 0.0012
Street Lighting	kW	$ 1.7797	$ 0.3965
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.5034	$ 0.5667

SLHI is an embedded distributor to Hydro One; therefore the company does not pay the Uniform Transmission rates charged by the IESO. Hydro One bills SLHI Transmission Network Service

Charges and Line Connection Service Charges under the Sub-Transmission Class. SLHI is not charged for Transformation Connection Service Charges.

Table 8.11 – 2011 Actual Transmission Charges to SLHI

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

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	18,772	$2.65	$ 49,746	18,772	$0.64	$ 12,014		$0.00		$ 12,014
February	16,899	$2.65	$ 44,782	16,899	$0.64	$ 10,815		$0.00		$ 10,815
March	14,445	$2.65	$ 38,279	14,445	$0.64	$ 9,245		$0.00		$ 9,245
April	12,879	$2.65	$ 34,129	12,879	$0.64	$ 8,243		$0.00		$ 8,243
May	9,567	$2.65	$ 25,353	9,567	$0.64	$ 6,123		$0.00		$ 6,123
June	7,607	$2.65	$ 20,159	7,607	$0.64	$ 4,868		$0.00		$ 4,868
July	8,188	$2.65	$ 21,698	8,188	$0.64	$ 5,240		$0.00		$ 5,240
August	7,970	$2.65	$ 21,121	7,970	$0.64	$ 5,101		$0.00		$ 5,101
September	8,788	$2.65	$ 23,288	8,815	$0.64	$ 5,642		$0.00		$ 5,642
October	10,804	$2.65	$ 28,631	10,804	$0.64	$ 6,915		$0.00		$ 6,915
November	15,607	$2.65	$ 41,359	15,607	$0.64	$ 9,988		$0.00		$ 9,988
December	15,090	$2.65	$ 39,989	15,090	$0.64	$ 9,658		$0.00		$ 9,658
Total	146,616	$ 2.65	$ 388,532	146,643	$ 0.64	$ 93,852	-	$ -	$ -	$ 93,852

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	18,772	$2.65	$ 49,746	18,772	$0.64	$ 12,014	-	$0.00	$ -	$ 12,014
February	16,899	$2.65	$ 44,782	16,899	$0.64	$ 10,815	-	$0.00	$ -	$ 10,815
March	14,445	$2.65	$ 38,279	14,445	$0.64	$ 9,245	-	$0.00	$ -	$ 9,245
April	12,879	$2.65	$ 34,129	12,879	$0.64	$ 8,243	-	$0.00	$ -	$ 8,243
May	9,567	$2.65	$ 25,353	9,567	$0.64	$ 6,123	-	$0.00	$ -	$ 6,123
June	7,607	$2.65	$ 20,159	7,607	$0.64	$ 4,868	-	$0.00	$ -	$ 4,868
July	8,188	$2.65	$ 21,698	8,188	$0.64	$ 5,240	-	$0.00	$ -	$ 5,240
August	7,970	$2.65	$ 21,121	7,970	$0.64	$ 5,101	-	$0.00	$ -	$ 5,101
September	8,788	$2.65	$ 23,288	8,815	$0.64	$ 5,642	-	$0.00	$ -	$ 5,642
October	10,804	$2.65	$ 28,631	10,804	$0.64	$ 6,915	-	$0.00	$ -	$ 6,915
November	15,607	$2.65	$ 41,359	15,607	$0.64	$ 9,988	-	$0.00	$ -	$ 9,988
December	15,090	$2.65	$ 39,989	15,090	$0.64	$ 9,658	-	$0.00	$ -	$ 9,658
Total	146,616	$ 2.65	$ 388,532	146,643	$ 0.64	$ 93,852	-	$ -	$ -	$ 93,852

Loss Factor

Determination of Loss Adjustment Factors

Total Loss Factor:

SLHI has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2007 to 2011. The calculations are summarized in Table 8-12 below.

Table 8-12 Line Loss Calculation

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2007	**2008**	**2009**	**2010**	**2011**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	94269858	82172582	76290185	74989583	76666329	80877707.4
A(2)	"Wholesale" kWh delivered to distributor (lower value)	93884880	81867475	76016629	74719842	76399313	80577627.8
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	93884880	81867475	76016629	74719842	76399313	80577627.8
D	"Retail" kWh delivered by distributor	89846017	77324320	71778509	70415620	72931754	76459244
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						0
F	Net "Retail" kWh delivered by distributor = **D - E**	89846017	77324320	71778509	70415620	72931754	76459244
G	Loss Factor in Distributor's system = **C / F**	1.044953167	1.058754542	1.059044414	1.061125955	1.047545257	1.053863779
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.034	1.034	1.034	1.034	1.034	1.034
	Total Losses						
I	Total Loss Factor = **G x H**	1.080481575	1.094752196	1.095051924	1.097204237	1.083161796	1.089695147

SLHI is fully embedded with Hydro One, therefore as per the Chapter 2 Filing requirements Appendix 2-R the supply facility loss factor (the "SFLF") is 1.034. The SFLF used in the calculations of the total loss factor above is based on Hydro One's Sub Transmission Loss, Embedded Delivery Points (Metering away from Station) of 1.034 found in Hydro One's Rate Order dated December 20, 2012, EB-201-0136, Appendix A, page 26 of 28.

Total Loss Factor by Class:

Table 8-13 sets out the class-specific Loss Factors used by SLHI in the calculation of commodity and other non-distribution charges.

Table 8-13 Total Loss Factor by Class

Loss Factors	
Supply Facilities Loss Factor (5 year average)	1.0340
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0539
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0433
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0897
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0788
Total Loss Factor - Primary Metered Customer > 5,000 kW	

Materiality Analysis on Distribution Losses

SLHI's Distribution Loss Adjustment factor is 5.39%. SLHI has taken a number of steps in order to reduce its distribution losses. The Hwy 72 upgrade capital project which began in 2007 and completed in 2012 along with the Moosehorn Road Voltage upgrade are expected to reduce line losses as explained in Exhibit 2. The implementation of smart meters has also contributed to reducing line loss through more accurate consumption data which reduces billing errors from human error. Smart Meters also provide better data in order to calculate unbilled revenue at the end of each fiscal year. The unbilled revenue calculation was also improved beginning in 2009 to provide increased accuracy.

As can be seen in Table 8-12, SLHI's Distribution losses have decreased by 1.36% from 2010 to 2011. The decrease can be explained in part by the Hwy 72 upgrade project. The majority of the work for this project was completed by the end of 2010.

SLHI's Total loss factor approved in the 2008 EDR Application was 6.42%, which was the five year average distribution loss from 2002 to 2006. 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. It should be noted that it is a challenge for SLHI to reduce losses to below 5% given our large service territory and low density.

RATE MITIGATION

As per the Filing Guidelines issued June 28, 2012, the applicant must file a mitigation plan if total bill increases for any rate classes exceed 10%. SLHI does not propose to implement a rate mitigation plan in this application. The bill impacts for all classes are less than 10%.

EXISTING RATE CLASSES

Residential:

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase.

General Service Less Than 50kW:

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service 50 to 4,999 kW:

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

Unmetered Scattered Load:

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Street Lighting:

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

EXISTING RATE SCHEDULE

SLHI has attached the Board's most recent Decision and Order from its 2012 Smart Meter Cost Recovery Rate Application (EB-2012-0245) which contains a complete schedule of existing rates as Appendix 8-A.

PROPOSED RATE CLASSES AND SPECIFIC SERVICE CHARGES

SLHI is not requesting any changes to the existing rate classes, or current specific service charges.

PROPOSED RATES AND CHARGES

A complete listing of the proposed rates and charges can be found in Exhibit 1, Tab 1, Schedule 2, Appendix A.

RECONCILIATION OF RATE CLASS REVENUE

The following Table 8-14 provides a reconciliation between the 2013 distribution rate calculations based on the 2013 Proposed Rates and the total base revenue required. Note the small difference is due to rounding.

Table 8-14: Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates		
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric	
								kWh	kW
Residential	Customers	2,323.00	2,323.00	2,323.00	34,980,266		$ 28.52	$ 0.0122	
GS < 50 kW	Customers	374.00	374.00	374.00	12,526,981		$ 44.98	$ 0.0086	
GS > 50 to 4,999 kW	Customers	56.00	56.00	56.00	25,251,296	63,706	$ 375.80		$ 1.3085
Streetlighting	Connections	531.00	531.00	531.00	499,759	1,507	$ 9.67		$ 25.4938
Unmetered Scattered Load	Connections	2.00	2.00	2.00	11,962		$ 23.56	$ 0.0091	
				-					
				-					
				-					
Total									

Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
$ 1,221,782.77	$ 1,222,636		$ 1,222,636	$ 854
$ 309,602.28	$ 309,069		$ 309,069	-$ 533
$ 335,896.90	$ 330,062	$ 5,830	$ 335,892	-$ 5
$ 100,036.40	$ 100,028		$ 100,028	-$ 8
$ 674.29	$ 674		$ 674	-$ 0
$ -			$ -	$ -
$ -			$ -	$ -
$ -			$ -	$ -
$ 1,967,992.63	$ 1,962,470	$ 5,830	$ 1,968,300	$ 307

RATE AND BILL IMPACTS

Appendix 8-B to this Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are shown using the applicable current approved rates and the proposed 2013 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

APPENDIX 8-A

EXISTING RATE SCHEDULE

ONTARIO ENERGY BOARD

DECISION AND ORDER

AUGUST 23, 2012

Sioux Lookout Hydro Incorporated
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

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

EB-2011-0102
EB-2012-0245

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	24.26
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until August 31, 2014	$	2.42
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	4.61
Distribution Volumetric Rate	$/kWh	0.0104
Low Voltage Service Rate	$/kWh	0.0030
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0035)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non RPP Customers	$/kWh	(0.0023)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0013

MONTHLY RATES AND CHARGES – Regulatory Component

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

Sioux Lookout Hydro Incorporated
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

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

EB-2011-0102
EB-2012-0245

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	43.11
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until August 31, 2014	$	3.09
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	5.18
Distribution Volumetric Rate	$/kWh	0.0082
Low Voltage Service Rate	$/kWh	0.0027
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0028)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non RPP Customers	$/kWh	(0.0023)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0011

MONTHLY RATES AND CHARGES – Regulatory Component

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

Sioux Lookout Hydro Incorporated
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

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

EB-2011-0102
EB-2012-0245

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered
General Service >1,000 to 4,999 kW interval metered.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	398.88
Distribution Volumetric Rate	$/kW	1.3832
Low Voltage Service Rate	$/kW	1.1187
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.8074)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non RPP Customers	$/kW	(0.8145)
Retail Transmission Rate – Network Service Rate	$/kW	2.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.4581
Retail Transmission Rate – Network Service Rate – Interval Metered >1,000 kW	$/kW	2.1260
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered >1,000 kW	$/kW	0.5062

MONTHLY RATES AND CHARGES – Regulatory Component

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

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EB-2012-0245

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	21.50
Distribution Volumetric Rate	$/kWh	0.0083
Low Voltage Service Rate	$/kWh	0.0027
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0081)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0011

MONTHLY RATES AND CHARGES – Regulatory Component

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

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STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	9.87
Distribution Volumetric Rate	$/kW	26.0218
Low Voltage Service Rate	$/kW	0.8534
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.1406)
Retail Transmission Rate – Network Service Rate	$/kW	1.5114
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.3542

MONTHLY RATES AND CHARGES – Regulatory Component

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

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microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.3741)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration		
Statement of Account	$	15.00
Duplicate invoices for previous billing	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	110.00
Disconnect/Reconnect Charge - At Meter After Regular Hours	$	245.00
Disconnect/Reconnect at pole – during regular hours	$	245.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	110.00
Install/Remove load control device – after regular hours	$	245.00
Temporary service – install and remove – overhead – no transformer	$	500.00
Temporary service – install and remove – underground – no transformer	$	300.00
Temporary service – install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

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EB-2011-0102
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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

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

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0642
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0535

APPENDIX 8-B

BILL IMPACTS

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ☐ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed 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	$ 28.5200	1	$ 28.52	$ 4.26	17.56%
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	$ -	$ 2.8300	1	$ 2.83	$ 2.83	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0104	800	$ 8.32	$ 0.0122	800	$ 9.76	$ 1.44	17.31%
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			$ 46.49	**$ 4.48**	**10.66%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0035	800	-$ 2.80	-$ 0.0028	800	-$ 2.24	$ 0.56	-20.00%
			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**			**$ 44.25**	**$ 5.04**	**12.85%**
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**			**$ 51.22**	**$ 6.22**	**13.83%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	851	$ 4.43	$ 0.0052	872	$ 4.53	$ 0.11	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	851	$ 0.94	$ 0.0011	872	$ 0.96	$ 0.02	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	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**			**$ 127.58**	**$ 8.01**	**6.70%**
HST		13%		$ 15.54	13%		$ 16.59	$ 1.04	6.70%
Total Bill (including HST)				$ 135.12			$ 144.16	$ 9.05	6.70%
Ontario Clean Energy Benefit [1]				-$ 13.51			-$ 14.42	-$ 0.91	6.74%
Total Bill on RPP (including OCEB)				**$ 121.61**			**$ 129.74**	**$ 8.14**	**6.69%**
Total Bill on TOU (before Taxes)				**$ 124.15**			**$ 132.27**	**$ 8.12**	**6.54%**
HST		13%		$ 16.14	13%		$ 17.19	$ 1.06	6.54%
Total Bill (including HST)				$ 140.29			$ 149.46	$ 9.17	6.54%
Ontario Clean Energy Benefit [1]				-$ 14.03			-$ 14.95	-$ 0.92	6.56%
Total Bill on TOU (including OCEB)				**$ 126.26**			**$ 134.51**	**$ 8.25**	**6.53%**

	Current	Proposed
Loss Factor (%)	6.42%	8.97%

Appendix 2-W
Bill Impacts

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

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

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 43.1100	1	$ 43.11	$ 44.9800	1	$ 44.98	$ 1.87	4.34%
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	$ -	$ 2.6300	1	$ 2.63	$ 2.63	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0082	2000	$ 16.40	$ 0.0086	2000	$ 17.20	$ 0.80	4.88%
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			$ 74.10	**$ 0.92**	**1.26%**
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**			**$ 67.90**	**$ 0.32**	**0.47%**
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**			**$ 83.37**	**$ 2.81**	**3.49%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2128	$ 11.07	$ 0.0052	2179	$ 11.33	$ 0.27	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2128	$ 2.34	$ 0.0011	2179	$ 2.40	$ 0.06	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	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**			**$ 289.22**	**$ 7.93**	**2.82%**
HST		13%		$ 36.57	13%		$ 37.60	$ 1.03	2.82%
Total Bill (including HST)				$ 317.86			$ 326.82	$ 8.96	2.82%
Ontario Clean Energy Benefit [1]				-$ 31.79			-$ 32.68	-$ 0.89	2.80%
Total Bill on RPP (including OCEB)				**$ 286.07**			**$ 294.14**	**$ 8.07**	**2.82%**
Total Bill on TOU (before Taxes)				**$ 278.07**			**$ 285.61**	**$ 7.54**	**2.71%**
HST		13%		$ 36.15	13%		$ 37.13	$ 0.98	2.71%
Total Bill (including HST)				$ 314.22			$ 322.74	$ 8.52	2.71%
Ontario Clean Energy Benefit [1]				-$ 31.42			-$ 32.27	-$ 0.85	2.71%
Total Bill on TOU (including OCEB)				**$ 282.80**			**$ 290.47**	**$ 7.67**	**2.71%**

Loss Factor (%)	6.42%	8.97%

Appendix 2-W
Bill Impacts

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 ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 398.8800	1	$ 398.88	$ 375.8000	1	$ 375.80	-$ 23.08	-5.79%
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	$ 1.3085	100	$ 130.85	-$ 7.47	-5.40%
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			$ 635.55	**-$ 13.52**	**-2.08%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.8074	100	-$ 80.74	-$ 1.3376	100	-$ 133.76	-$ 53.02	65.67%
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**			**$ 398.27**	**-$ 88.61**	**-18.20%**
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**			**$ 686.82**	**-$ 46.28**	**-6.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	31926	$ 166.02	$ 0.0052	32691	$ 169.99	$ 3.98	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	31926	$ 35.12	$ 0.0011	32691	$ 35.96	$ 0.84	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	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**			**$ 3,934.14**	**$ 25.09**	**0.64%**
HST		13%		$ 508.18	13%		$ 511.44	$ 3.26	0.64%
Total Bill (including HST)				$ 4,417.22			$ 4,445.58	$ 28.36	0.64%
Ontario Clean Energy Benefit [1]				-$ 441.72			-$ 444.56	-$ 2.84	0.64%
Total Bill on RPP (including OCEB)				**$ 3,975.50**			**$ 4,001.02**	**$ 25.52**	**0.64%**
Total Bill on TOU (before Taxes)				**$ 3,678.77**			**$ 3,698.03**	**$ 19.27**	**0.52%**
HST		13%		$ 478.24	13%		$ 480.74	$ 2.50	0.52%
Total Bill (including HST)				$ 4,157.01			$ 4,178.78	$ 21.77	0.52%
Ontario Clean Energy Benefit [1]				-$ 415.70			-$ 417.88	-$ 2.18	0.52%
Total Bill on TOU (including OCEB)				**$ 3,741.31**			**$ 3,760.90**	**$ 19.59**	**0.52%**

Appendix 2-W
Bill Impacts

Customer Class: **General Service > 1000 kW - Interval Metered**

Consumption 1000 kW ; 200000 kWh

May 1 - October 31 | November 1 - April 30 (Select this radio button for applications filed after C

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 398.8800	1	$ 398.88	$ 375.8000	1	$ 375.80	-$ 23.08	-5.79%
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	1000	$ 1,383.20	$ 1.3085	1000	$ 1,308.50	-$ 74.70	-5.40%
Smart Meter Disposition Rider			1000	$ -		1000	$ -	$ -	
LRAM & SSM Rate Rider			1000	$ -		1000	$ -	$ -	
Low Voltage Rate Adder	per kW	$ 1.1187	1000	$ 1,118.70	$ 1.2890	1000	$ 1,289.00	$ 170.30	15.22%
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Sub-Total A				$ 2,900.78			$ 2,973.30	**$ 72.52**	**2.50%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.8074	1000	-$ 807.40	-$ 1.3376	1000	-$ 1,337.60	-$ 530.20	65.67%
Global Adjustment Rate Rider	per kW	-$ 0.8145	1000	-$ 814.50	-$ 1.0352	1000	-$ 1,035.20	-$ 220.70	27.10%
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Low Voltage Service Charge			1000	$ -		1000	$ -	$ -	
Smart Meter Entity Charge						1000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,278.88**			**$ 600.50**	**-$ 678.38**	**-53.04%**
RTSR - Network	per kW	$ 2.1260	1000	$ 2,126.00	$ 2.5034	1000	$ 2,503.40	$ 377.40	17.75%
RTSR - Line and Transformation Connection	per kW	$ 0.5062	1000	$ 506.20	$ 0.5667	1000	$ 566.70	$ 60.50	11.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,911.08**			**$ 3,670.60**	**-$ 240.48**	**-6.15%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	210700	$ 1,095.64	$ 0.0052	215760	$ 1,121.95	$ 26.31	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	210700	$ 231.77	$ 0.0011	215760	$ 237.34	$ 5.57	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	200000	$ 1,400.00	$ 0.0070	200000	$ 1,400.00	$ -	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	209700	$ 18,243.90	$ 0.0870	214760	$ 18,684.12	$ 440.22	2.41%
TOU - Off Peak	per kWh	$ 0.0630	134848	$ 8,495.42	$ 0.0630	138086	$ 8,699.44	$ 204.02	2.40%
TOU - Mid Peak	per kWh	$ 0.0990	37926	$ 3,754.67	$ 0.0990	38837	$ 3,844.84	$ 90.17	2.40%
TOU - On Peak	per kWh	$ 0.1180	37926	$ 4,475.27	$ 0.1180	38837	$ 4,582.74	$ 107.47	2.40%
Total Bill on RPP (before Taxes)				**$ 24,956.64**			**$ 25,188.26**	**$ 231.62**	**0.93%**
HST		13%		$ 3,244.36	13%		$ 3,274.47	$ 30.11	0.93%
Total Bill (including HST)				$ 28,201.00			$ 28,462.73	$ 261.73	0.93%
Ontario Clean Energy Benefit [1]				-$ 2,820.10			-$ 2,846.27	-$ 26.17	0.93%
Total Bill on RPP (including OCEB)				**$ 25,380.90**			**$ 25,616.46**	**$ 235.56**	**0.93%**
Total Bill on TOU (before Taxes)				**$ 23,364.11**			**$ 23,557.17**	**$ 193.06**	**0.83%**
HST		13%		$ 3,037.33	13%		$ 3,062.43	$ 25.10	0.83%
Total Bill (including HST)				$ 26,401.44			$ 26,619.60	$ 218.16	0.83%
Ontario Clean Energy Benefit [1]				-$ 2,640.14			-$ 2,661.96	-$ 21.82	0.83%
Total Bill on TOU (including OCEB)				**$ 23,761.30**			**$ 23,957.64**	**$ 196.34**	**0.83%**

Loss Factor (%) Current: 5.35% Proposed: 7.88%

Appendix 2-W
Bill Impacts

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 ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 21.5000	1	$ 21.50	$ 23.5600	1	$ 23.56	$ 2.06	9.58%
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	$ 0.0091	498	$ 4.53	$ 0.40	9.64%
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			$ 29.64	**$ 2.66**	**9.85%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0081	498	-$ 4.03	-$ 0.0019	498	-$ 0.95	$ 3.09	-76.54%
			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**			**$ 28.69**	**$ 5.75**	**25.04%**
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**			**$ 32.54**	**$ 6.37**	**24.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	530	$ 2.76	$ 0.0052	543	$ 2.82	$ 0.07	2.40%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	530	$ 0.58	$ 0.0011	543	$ 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	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**			**$ 80.17**	**$ 7.47**	**10.28%**
HST		13%		$ 9.45	13%		$ 10.42	$ 0.97	10.28%
Total Bill (including HST)				$ 82.14			$ 90.59	$ 8.45	10.28%
Ontario Clean Energy Benefit [1]				-$ 8.21			-$ 9.06	-$ 0.85	10.35%
Total Bill on RPP (including OCEB)				**$ 73.93**			**$ 81.53**	**$ 7.60**	**10.27%**
Total Bill on TOU (before Taxes)				**$ 75.54**			**$ 83.09**	**$ 7.54**	**9.98%**
HST		13%		$ 9.82	13%		$ 10.80	$ 0.98	9.98%
Total Bill (including HST)				$ 85.37			$ 93.89	$ 8.52	9.98%
Ontario Clean Energy Benefit [1]				-$ 8.54			-$ 9.39	-$ 0.85	9.95%
Total Bill on TOU (including OCEB)				**$ 76.83**			**$ 84.50**	**$ 7.67**	**9.99%**

	Current	Proposed
Loss Factor (%)	6.42%	8.97%

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 120 kW; 40000 kWh; 531 Connections

May 1 - October 31 — November 1 - April 30 (Select this radio button for applications filed after (

	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	$ 9.6700	531	$ 5,134.77	-$ 106.20	-2.03%
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	$ 25.4938	120	$ 3,059.26	-$ 63.36	-2.03%
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			$ 8,313.62	**-$ 152.38**	**-1.80%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 2.1406	120	-$ 256.87	$ 1.5062	120	$ 180.74	$ 437.62	-170.36%
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**			**$ 8,389.69**	**$ 180.56**	**2.20%**
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**			**$ 8,652.01**	**$ 219.01**	**2.60%**
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 - 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**			**$ 12,986.02**	**$ 314.18**	**2.48%**
HST		13%		$ 1,647.34	13%		$ 1,688.18	$ 40.84	2.48%
Total Bill (including HST)				$ 14,319.18			$ 14,674.20	$ 355.02	2.48%
Ontario Clean Energy Benefit [1]				-$ 1,431.92			-$ 1,467.42	-$ 35.50	2.48%
Total Bill on RPP (including OCEB)				**$ 12,887.26**			**$ 13,206.78**	**$ 319.52**	**2.48%**
Total Bill on TOU (before Taxes)				**$ 12,360.47**			**$ 12,666.88**	**$ 306.41**	**2.48%**
HST		13%		$ 1,606.86	13%		$ 1,646.69	$ 39.83	2.48%
Total Bill (including HST)				$ 13,967.33			$ 14,313.57	$ 346.24	2.48%
Ontario Clean Energy Benefit [1]				-$ 1,396.73			-$ 1,431.36	-$ 34.63	2.48%
Total Bill on TOU (including OCEB)				**$ 12,570.60**			**$ 12,882.21**	**$ 311.61**	**2.48%**

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

Exhibit	Tab	Schedule	Appendix	Contents
9 – Deferral and Variance Accounts				
	1	1		Overview
		2		Previous Deferral and Variance Account Disposition
	2	1		Status of Deferral and Variance Accounts
		2		Deferral and Variance Account Balances
		3		Accounts Requested for Disposition
		4		Method of Disposition
	3	1		Stranded Assets
	4	1		Green Energy Plan - Funding Adder
	5	1		LRAM Recovery
			9-A	2013 EDDVAR Continuity Schedule

DEFERRAL AND VARIANCE ACCOUNTS

Overview

The information contained in this exhibit includes the status and description of SLHI's deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

PREVIOUS DEFERRAL / VARIANCE ACCOUNT DISPOSITION

2012 Smart Meter Funding and Cost Recovery – Final Disposition

On August 23, 2012, The Ontario Energy Board's Decision and Order EB-2012-0245 approved a two-year disposition rate rider for the Smart Meter Disposition balance in the amount of $162,501 to be recovered and a Smart Meter Incremental Revenue Rate Rider to be collected over one year in the amount of $151,629. In 2012, the approved balances were transferred from the deferral accounts 1555 and 1556 to the corresponding capital and OM&A accounts.

2012 IRM

On April 19, 2012 the Ontario Energy Board's Decision and Order EB-2011-0102 approved a one year disposition of Group 1 account balances as of December 2010, effective May 1, 2012. The account balances were transferred to account 1595 and rates for disposition are approved until April 30, 2013.

In the same application, the Board approved, on a final basis, the disposition of a debit balance of $2,176, in Account 1521 Special Purpose Charge ("SPC"). In 2012, the approved balance was transferred to a sub-account of 1595 to be recovered over a one year period.

Also, in the 2012 IRM decision, the Board approved the disposition of the credit balance in Account 1562 Deferred Payments in Lieu of Taxes ("PILs") of $143,461, on a final basis over a one year period. In 2012, the approved balance was transferred to a sub-account of 1595 to be refunded over a one year period.

2011 IRM

On March 28th 2011 the Ontario Energy Board's Decision and Order EB-2010-0114 approved a one year disposition of Group 1 account balances as of December 31st 2009, effective May 1, 2011. The account balances were transferred to a sub-account of 1595 and rates for disposition were approved until April 30, 2012.

2010 IRM

On April 20th 2010 the Ontario Energy Board's Decision and Order EB-2009-0249 approved a one year disposition of Group 1 account balances as of December 31st 2008, effective May 1, 2010. The account balances were transferred to account 1595 and rates for disposition were approved until April 30, 2011.

2009 IRM

The Ontario Energy Board's Decision and Order pertaining to EB-2008-0212 did not contain any decisions regarding Deferral/Variance Account Disposition.

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS:

This Schedule contains the status of Deferral and Variance Accounts ("DVAs") currently used by SLHI. The balances as at December 31, 2011 and the proposed recovery amounts are summarized in Table 2.1 following the descriptions of each account:

GROUP 1 ACCOUNTS

1550 LV Variance Account

This Account is used to record the net of the low voltage transactions, which are not part of the electricity wholesale market. Monthly, this account is used to record the net amounts charged by host distributor(s) to an embedded distributor for transmission or low voltage services (USoA 4750) and the amount billed to the embedded distributor's customers based on approved LV rate(s) (USoA 4075). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1550. The requested amount is a debit of $17,221.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. If applicable, embedded distributors shall also use this account to record the net difference between the amount charged by the host distributor (based on settlement invoice) for wholesale market services and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. SLHI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1580. The requested amount is a credit of ($84,441).

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for network services. If applicable, embedded distributors shall also use this account to record the net difference between the amount charged by the host distributor (based on settlement invoice) for transmission network services and the amount billed to customers using the OEB-approved Transmission Network Charge Rate. SLHI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1584. The requested amount is a debit of $1,755.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for connection services. If applicable, embedded distributors shall also use this account to record the net difference between the amount charged by the host distributor (based on settlement invoice) for transmission connection services and the amount billed to customers using the OEB-approved Transmission Connection Charge Rate. SLHI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1586. The requested amount is a credit of ($15,952).

1588 Retail Settlement Variance Account – Power (excluding Global Adjustment)

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to SLHI using the settlement invoice from the Independent Electricity System Operator (IESO), host distributor or embedded generator. SLHI uses the accrual method. The variance between Board-approved and actual line losses is reflected in Account 1588 for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 - Power. The requested amount is a debit of $42,042.

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to SLHI using the settlement invoice from Hydro One. SLHI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 sub account Global

Adjustment through a separate non-RPP rate rider. The requested amount is a credit of ($68,906).

1595 Disposition and Recovery of Regulatory Balances

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

Sub-Account 2008 for EB-2007-0785

In accordance with the OEB EB-2007-0785 Decision and Order for SLHI's 2008 COS Application, the December 31, 2006 debit balance of $360,604 including interest forecast to April 30, 2008 was transferred to a sub-account of 1595 November 2008. This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payment/credits made to customers. Separate accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recover. The recovery period ended April 30, 2011 and the residual balance has been audited. SLHI is requesting recovery of the credit balance of ($47,485) as at December 31, 2011 including forecasted carrying charges to April 30, 2013.

Sub Account 2010 for EB-2009-0249

In accordance with the OEB EB-2009-0249 Decision and Order for SLHI's 2010 IRM, the December 3, 2008 credit balance of ($83,147) including interest forecast to April 30, 2009 was transferred to a sub-account of 1595 in April 2010. SLHI was further ordered to record the shared tax savings resulting from the Ontario Capital Tax rate decrease for 2010. The credit balance of ($1,001) was recorded in the sub-account of 1595 for disposition at a future rate proceeding. The recovery period ended April 30, 2011 and the residual balance has been audited. SLHI is requesting recovery of the credit balance of

($153,167) as at December 31, 2011 including forecasted carrying charges to April 30, 2013.

GROUP 2 ACCOUNTS

1508 Other Regulatory Assets – Sub-account IFRS Transition Costs

This account includes amounts paid for one-time incremental costs for the transition to International Financial Reporting Standards (IFRS). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

SLHI has established account 1508 – sub account IFRS Transition Costs in accordance with the Board Requirements. Given the recent deferral of IFRS implementation until 2014, 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.

1518 Retail Settlement Variance Account – Retail

This account is used to recover the net differences between the revenues recovered from Retailer Service Agreements and Billing options and the cost of managing the retailer contracts.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, SLHI is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1518 – RCVA Retail. The requested amount is a debit of $12,316.

1555 Smart Meter Capital and Recoveries – Sub-Accounts

Amounts recorded in this account include the revenue from smart meter adders approved by the Board for smart meters and related capital costs incurred by SLHI. On August 23, 2012 the Ontario Energy Board's Decision and Order EB-2012-0245 approved disposition of this account on a final basis. The corresponding rate rider is effective until August 31, 2014. In 2012, the approved balance was transferred to the corresponding revenue and capital accounts.

In the same order the Board authorized SLHI to continue to track Stranded Meter Costs in the Sub Account – Stranded Meter Costs. SLHI is proposing to dispose of the balance in this sub-account. The details can be found in Exhibit 9, Tab 3, Schedule 1.

1556 Smart Meter OM&A Variance Account

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. On August 23, 2012, the Ontario Energy Board's Decision and Order EB-2012-0245 approved the disposition of this account on a final basis. The corresponding rate rider is effective until August 31, 2014. In 2012, the approved balances were transferred to the corresponding OM&A accounts.

1562 Deferred Payment in Lieu of Taxes

This account records the amount resulting from the Board approved PILs methodology for determining the 2001 Deferral Account Allowance and the PILs proxy amount determined for 2002 and subsequent years. The amount determined using the Board approved PILs methodology is recorded equally over the applicable PILs period. The 2001 PILs deferral Account Allowance is recorded in three equal installments in October, November and December since December 31, 2001 is the taxation year end. For a full year each applicable proxy is divided by 12, and a monthly amount is posted for each applicable period.

In accordance with the Decision and Order Dated April 19, 2012, SLHI was ordered to transfer the balance of Account 1562 to the principal and interest carrying charge sub-accounts of Account 1595. SLHI has transferred a credit balance in Account 1562 Deferred Payments in Lieu of Taxes (PILs) of ($143,461), on a final basis to be paid over a one year period to its customers**.**

1568 LRAM Variance Account

This account includes the lost revenue adjustment mechanism ("LRAM") variances in relation to the conservation and demand management ("CDM") programs or activities undertaken by SLHI in accordance with Board-prescribed requirements. SLHI did not record any variances for programs prior to 2011. More detail in regards to the LRAM claim can be found in the LRAM Recovery Section below.

1592 PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits (ITC's)

This account is used to record the incremental ITC received on distribution revenue requirement items that were previously subject to PST and which now become subject to HST. Tracking of these amounts will continue in this deferral account until the effective date of SLHI's next cost of service rate order. Fifty percent (50%) of the confirmed balance in this account shall be returnable to the rate payers.

Account 1592 – Sub-account HST includes a credit balance of ($12,886) which represents 100% of the HST balance as at December 31, 2011. For 2013, SLHI is requesting 50% disposition of the December 31, 2011 audited balance plus forecasted interest of ($250) from January 1, 2012 through to April 30, 2013 for a total of ($13,136). The requested amount is a credit balance of ($6,568). See table 9-20 below.

Table 9-20: Deferred PILs Account 1592 Balances	
Tax Item	**as at December 31, 2011**
PILs Tax Varaince for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) - Represents 100% of the account balances as a t December 31, 2011	-12,745
Carrying Charges as at December 31, 2011	-141
Carrying Charges calculated from Jan 1/12 to April 30/13	-250
Subtotal	-13,136
To be refunded back to customers (50%)	**-6,568**

As indicated in the table above, the only type of tax item in Account 1592 is the ITCs that have been deferred starting July 1, 2010 through to December 31, 2011, thus, the guidance provided in the FAQ of July 2007 is not applicable to SLHI.

In accordance with the filing requirements, SLHI has revised the deferral and variance account continuity schedule to include account 1592 as a Group 2 account and has recorded the above-noted amounts therein.

Table 9.21 below, shows the HST savings each year including carrying charges and also the total applicable spending that was captured in the ITC calculations.

Table 9-21: HST Savings by Year					
	2010 Actual HST Savings	**2011 Actual Savings**	**Total**	**Jan 1/12 to Apr 31/13 Interest**	**Grand Total**
OM&A	3,544	9,058	**12,602**		**12,602**
Capital	84	59	**143**		**143**
Interest	27	114	**141**	250	**391**
Total HST Savings	3,655	9,231	**12,886**	250	**13,136**
50% Refund to Customers					**6,568**
Actual purchases					
OM&A	44306	113223	157,529		
Capital	212172	194252	406,424		
Total	256478	307475	563953		

In the December 2010 FAQ response to Q#1, the Board directed distributors to record the ITCs in Account 1592 with the offsetting entry to be recorded in a new sub-account that will serve as a contra account. For regulatory purposes, this will have a zero net effect on reporting. Only the balance in "Sub-account HST/OVAT Input Tax Credits (ITCs)" should be reported for disposition of the account balance, except for purposes of reporting under the Electricity Reporting & Record Keeping Requirements, which should include both sub-accounts netting to zero.

Table 9-22 below, shows a reconciliation of Account 1592 between the 2011 RRR 2.1.7, the Audited Financial Statements, and the Continuity Schedule in which the only variance item being the 50% variance between the Continuity Schedule and the 2011 RRR 2.1.7. The HST Deferral Sub-account contra contains 100% of the variance, but is not included in the total claim in the Continuity Schedule but as a memo only.

Table 9-22: Reconciliation of Account 1592

as at December 31, 2011					
	A	B	C	B-A	C-A
	2011 RRR 2.1.7	Audited Financial Statements	Continuity Schedule	Variance	Variance
HST Deferral sub-account	-12,886	0	-6,444	12,886	6,442
HST Deferral Sub-account contra	12,886	0	12,886	-12,886	0
Total	**0**	**0**	**6,442**	**0**	**6,442**

As noted above, SLHI has recorded variances on a monthly basis in the sub-account of Account 1592 to cover the period starting July 1, 2010 and will continue to do so until April 30, 2013, with May 1, 2013 being the start of the Test Year. In regards to the methodology of calculating the ITCs, SLHI sought to adhere to the Board's Decision and Order in EB-2009-0249 to start recording the ITCs in deferral account 1592 beginning July 1, 2010. Although requested prior to this commencement date, guidance on a simplified method was not provided until the Board's December 2010 FAQ, particularity Question #4. As a result, SLHI opted to calculate the ITCs on a transactional basis.

SLHI developed a process to calculate the HST savings for 2 major groups of costs: OM&A Expenses and Capital purchases. At the onset of developing the process, a list of applicable transactions that were previously subject to PST but charged HST post July 1, 2010 was developed and all accounts within the general ledger that included these applicable transactions were identified. The methodology used for each of these groups is discussed further below.

In calculating the OM&A ITCs on a monthly basis, SLHI reviews all transactions that occurred in the applicable accounts on a monthly basis to calculate the ITCs. Every transaction is reviewed since there may be a specific purchase that would not qualify as an applicable transaction (i.e. was not subject to PST prior to July 1, 2010). The calculation for each transaction for the ITC is as follows:

(Purchase amount*0.13)*.08/.13

For capital purchases post July 1, 2010, SLHI analyzes each purchase within the applicable accounts identified as potentially being included in the ITC calculation on a monthly basis. The monthly ITC amount is determined as follows:

((Purchase amount*.13)*.08/.13)/useful life in years/12 months

The calculated amount for each purchase above is brought forward in the monthly ITC amount until April 30, 2013.

Please note that carrying charges are calculated on the opening monthly net principal balance using the Board's prescribed interest rate.

The accounting entry to post the ITC on a monthly basis is as follows:

Debit 1592 Sub-account HST/OVAT ITCs – OM&A Contra

Debit 1592 Sub-account HST/OVAT ITCs – Capital Contra

Debit 1592 Sub-account HST/OVAT ITCs – Carrying Charges Contra

Credit 1592 Sub-account HST/OVAT ITCs – OM&A

Credit 1592 Sub-account HST/OVAT ITCs – Capital

Credit 1592 Sub-account HST/OVAT ITCs – Carrying Charges

SLHI requests leave to discontinue tracking HST/OVAT ITC as at April 30, 2013. SLHI also requests the Board to allow Account 1592 remain open, pending Board approval to discontinue tracking costs effective April 30, 2013 and until such time as SLHI files its 2014 IRM rate application at which time SLHI will apply to the Board for an order to clear any audited debit or credit balance remaining in Account 1592.

DEFERRAL AND VARIANCE ACCOUNT BALANCES

The following Table 9.23 contains account balances from the 2011 Audited Financial Statements as at December 31, 2011 and agrees to the 2011 year end balances for RRR filing E2.1.7 Trial Balance as filed April 30, 2012 with the OEB.

Table 9-23: December 31, 2011 Audited Balances - Deferral and Variance Accounts

Group 1 Deferral Variance Accounts	Account	Principal	Interest	Total
LV Variance Account	1550	59,673	1,310	60,983
RSVA - Wholesale Market Service Charge	1580	-192,373	-2,287	-194,660
RSVA - Retail Transmission Network Charge	1584	-12,016	126	-11,890
RSVA - Retail Transmission Connection Charge	1586	-66,320	-1,027	-67,347
RSVA - Power (excluding Global Adjustment)	1588	-139,590	1,561	-138,029
RSVA - Power - Sub-account Global Adjustment	1588	-129,990	-766	-130,756
Recovery of Regulatory Asset Balances	1590	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	302,964	36,349	339,313
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595			0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-463,749	57,194	-406,555
Sub-Total		**-641,401**	**92,460**	**-548,941**
Group 2 Deferrral/Variance Accounts				
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	17,500		17,500
Retail Cost Variance Account - Retail	1518	11,700	387	12,087
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-12,886	-250	-13,136
Sub-Total		**16,314**	**137**	**16,451**
Group 1 & 2 Grand Totals		**-625,087**	**92,597**	**-532,490**

Please note that Account 1592 has a contra account, and thus, for OEB Reporting purposes and on the Audited Financial Statements the balance is $0. The above Table represents the 50% of the HST savings before being contraed, which is to be refunded back to SLHI's customers.

SLHI confirms that all of the above accounts will continue on a going forward basis unless otherwise directed by the Board.

SLHI confirms that it has not made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in both Cost of Service and IRM proceedings.

Energy Sales and COP Expenses vs. Audited Financial Statements

In accordance with the Board's Filing Guidelines, Table 9-23.1 below details the 2011 energy sales and cost of power expense by USoA account number. The Energy Sales of $6,162,656 is reconciled to the 2011 Audited Financial Statement figure of $6,168,149 when the Distribution portion of the revenue adjustment is removed from account 4050, Revenue Adjustment. This relates to unbilled revenue for 2011. The $390 includes all unbilled revenue, $5,492 is the distribution revenue included in this figure.

Table 9-23.1: 2011 Cost of Power Expense Accounts

Energy Sales		**2011**
4050	Revenue Adjustment	-390.15
4055	Energy Sales for resale	-5,064,492
4062	Billed WMS	-418,570
4066	Billed NW	-369,827
4068	Billed CN	-85,155
4075	Billed - LV	-209,180
4324	Special Purpose Charge Recovery	-15,042
		-6,162,656
Cost of Power		**2011**
4705	Power Purchased	5,088,330
4708	Charges - WMS	414,988
4714	Charges - NW	366,053
4716	Charges - CN	87,409
4750	Charges - LV	196,326
5681	Special Purpose Charge Expense	15,042
		6,168,149
	Adjustment for Unbilled Revenue - Distribution Only	-5,492
Net Difference		0

Table 9-24 provides the interest rates that have been used to calculate actual forecast carrying charges on the accounts in accordance with the methodology approved by the Board in EB-2006-0117 on November 28, 2006.

Table 9.24 - Interest Rates Applied to Deferral and Variance Accounts

Quarter by Year	Prescribed Interest Rate
Q1 2005	7.25%
Q2 2005	7.25%
Q3 2005	7.25%
Q4 2005	7.25%
Q1 2006	7.25%
Q2 2006	4.14%
Q3 2006	4.59%
Q4 2006	4.59%
Q1 2007	4.59%
Q2 2007	4.59%
Q3 2007	4.59%
Q4 2007	5.14%
Q1 2008	5.14%
Q2 2008	4.08%
Q3 2008	3.35%
Q4 2008	3.35%
Q1 2009	2.45%
Q2 2009	1.00%
Q3 2009	0.55%
Q4 2009	0.55%
Q1 2010	0.55%
Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011	1.47%
Q2 2011	1.47%
Q3 2011	1.47%
Q4 2011	1.47%
Q1 2012	1.47%
Q2 2012	1.47%
Q3 2012	1.47%
Q4 2012	1.47%
Q1 2013	1.47%

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

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

SLHI has followed the guidelines in the Report of the Board and requests disposition over a one-year period. SLHI has provided a continuity schedule of the accounts listed below in the Excel Workbook named 2013_EDDVAR_Continuity_Schedule_CoS_V2_SLHI submitted with this application.

SLHI is requesting the disposition of the following Group 1 and Group 2 Accounts shown in Tables 9-25, 9-26 and 9-27. These amounts are comprised of the audited balances as of December 31, 2011 and the forecasted interest through April 30, 2013.

Table 9-25: Group 1 Deferral/Variance Accounts - Excluding 1588 GA Sub-account

Group 1 Deferral/Variance Accounts		Principal (Dec 31/11)	Interest (Dec 31/11)	Prinicipal Disposition in 2012 EB-2011-0102	Interest Disposition in 2012 EB-2011-0102	Projected Interest to Dec 31/12	Projected Interest Jan 1/13 to Apr 30/13	Total
1550	LV Variance Account	59,673	1,310	44,149	-83	228	76	17,221
1580	RSVA - Wholesale Market Service Charge	-192,373	-2,287	-109,753	-2,086	-1,215	-405	-84,441
1584	RSVA - Retail Transmission Network Charge	-12,016	126	-13,347	-272	20	7	1,756
1586	RSVA - Retail Transmission Connection Charge	-66,320	-1,027	-50,583	-1,121	-231	-77	-15,951
1588	RSVA - Power (excluding Global Adjustment)	-139,590	1,561	-179,717	432	590	197	42,043
1590	Recovery of Regulatory Asset Balances	1	13	1	13	0	0	0
1595	Disposition and Recovery/Refund of Regulatory Balances (2008)	302,964	36,349	347,330	38,599	-652	-217	-47,485
1595	Disposition and Recovery/Refund of Regulatory Balances (2009)						0	0
1595	Disposition and Recovery/Refund of Regulatory Balances (2010)	-213,808	64,832			-3,143	-1,048	-153,167
Total		**-261,469**	**100,877**	**38,080**	**35,482**	**-4,403**	**-1,467**	**-240,024**

Table 9-26 Group 2 Deferral/Variance Accounts

Group 2 Deferral/Variance Accounts		Principal (Dec 31/11)	Interest (Dec 31/11)	Prinicipal Disposition in 2012 EB-2011-0102	Interest Disposition in 2012 EB-2011-0102	Projected Interest to Dec 31/12	Projected Interest Jan 1/13 to Apr 30/13	Total
1508	Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs	17,500	0	0	0	257	86	17,843
1518	Retail Cost Variance Account - Retail	11,700	387	0	0	172	57	12,316
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Acount HST/OVAT Input Tax Credits (ITCs)	-6,373	-71	0	0	-94	-32	-6,568
Total		**22,828**	**317**	**0**	**0**	**336**	**112**	**23,591**

Table 9-27: 1588 GA Sub-Account

		Principal (Dec 31/11)	Interest (Dec 31/11)	Prinicipal Disposition in 2012 EB-2011-0102	Interest Disposition in 2012 EB-2011-0102	Projected Interest to Dec 31/12	Projected Interest Jan 1/13 to Apr 30/13	Total
1588	RSVA - Power - Sub-account - Global Adjustment	-129,990	-766	-60,781	-2,425	-1,017	-339	-68,906
Total		**-129,990**	**-766**	**-60,781**	**-2,425**	**-1,017**	**-339**	**-68,906**

SLHI confirms that the IESO Global Adjustment Charge has been pro-rated into the RPP and non-RPP portions.

METHOD OF DISPOSITION

Allocators

SLHI submits the following Allocators in Table 9-28 which are used to assign the Group 1 and Group 2 balances to each rate class. Please note that the billing determinants used is SLHI's 2011 actuals as filed in the 2011 RRR filing.

Table 9-28: Allocation by Customer Class

Rate Class	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]
Residential	kWh	2,324	32,694,600		1,778,411	-	$ 985,990	37%	32%	0%	47%
General Service Less Than 50 kW	kWh	379	12,624,003		174,258	-	$ 325,469	19%	14%	0%	22%
General Service 50 to 4,999 kW	kW	52	27,265,781	66,653	24,781,997	60,581	$ 426,978	43%	53%	0%	30%
Unmetered Scattered Load	kWh	3	15,597			-	$ 3,194	0%	0%	0%	0%
Street Lighting	kW	532	498,452	1,446	494,480	1,434	$ 33,008	1%	1%	0%	1%
Total		**3,290**	**73,098,433**	**68,099**	**27,229,146**	**62,016**	**$ 1,774,639**	**100%**	**100%**	**0%**	**100%**

Rate Class	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]
Residential	kWh	71%	45%	0%	7%	0%	56%	37%	32%	0%	47%
General Service Less Than 50 kW	kWh	12%	17%	0%	1%	0%	18%	19%	14%	0%	22%
General Service 50 to 4,999 kW	kW	2%	37%	98%	91%	98%	24%	43%	53%	0%	30%
Unmetered Scattered Load	kWh	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Street Lighting	kW	16%	1%	2%	2%	2%	2%	1%	1%	0%	1%
Total		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**0%**	**100%**

Table 9-29 outlines the allocators used to determine the proposed regulatory asset rate rider by rate class for the Deferral and Variance Accounts.

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		12,604	2,055	282	16	2,885
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	12,316		8,700	1,419	195	11	1,991
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	0		0	0	0	0	0
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		**30,159**		**21,304**	**3,474**	**477**	**28**	**4,877**
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	(6,568)		(4,640)	(757)	(104)	(6)	(1,062)
Total of Account 1562 and Account 1592		**(6,568)**		**(4,640)**	**(757)**	**(104)**	**(6)**	**(1,062)**
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)		**(216,435)**		**(90,692)**	**(38,735)**	**(89,157)**	**(30)**	**2,178**
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)		**(285,341)**		**(95,192)**	**(39,176)**	**(151,870)**	**(30)**	**927**

Calculation of Rate Riders

Table 9-30 summarizes the variables used to determine the proposed regulatory asset rate rider by rate class for the Group 1 and Group 2 accounts, excluding the Non-RPP rate rider for the 1588 Sub-Account Global Adjustment. The billing determinants are based on the 2011 Actuals and calculated for a one-year disposition period.

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	-$90,692	-0.0028
General Service Less Than 50 kW	kWh	12,624,003	-$38,735	-0.0031
General Service 50 to 4,999 kW	kW	66,653	-$89,157	-1.3376
Unmetered Scattered Load	kWh	15,597	-$30	-0.0019
Street Lighting	kW	1,446	$2,178	1.5062
Total			**-$216,435**	

Table 3.4 summarizes the variables used to determine the proposed non-RPP global adjustment rate rider by rate class. The billing determinants are based on the 2011 Actual non-RPP volume data and calculated for a one-year disposition period.

Table 9-31: 2013 Non-RPP Global Adjustment Rate Rider by Class

Rate Class	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-account - Global Adjustment	Rate Rider for RSVA - Power - Sub-account - Global Adjustment
Residential	kWh	1,778,411	-$4,500	-0.0025
General Service Less Than 50 kW	kWh	174,258	-$441	-0.0025
General Service 50 to 4,999 kW	kW	60,581	-$62,713	-1.0352
Unmetered Scattered Load	kWh	0	$0	0.0000
Street Lighting	kW	1,434	-$1,251	-0.8723
Total			**-$68,906**	

STRANDED METER COSTS

On August 23, 2012 SLHI received its rate order from the Board in regards to its Smart Meter Cost Recovery Application EB-2012-0245. Smart meters had been 100% installed for Residential and General Service < 50 kW customers and costs incurred up to December 31, 2011 and the incremental revenue requirement for OM&A costs in 2012 were approved by the Board. A rate class specific Smart Meter Disposition Rate Rider ("SMDR") and Smart Meter Incremental Rate Rider ("SMIRR") were approved to be in effect for 24 months and 8 months, respectively. On page 16 of SLHI's response to Board Staff interrogatory Question #17 regarding the proposed recovery of stranded meter costs in its next cost of service application, the following was stated:

"The NBV of stranded conventional meters as of December 31, 2012 are estimated to be $181,592. The residential portion of this is $156,169 and GS < 50 customer class is $25,423."

In this current 2013 Cost of Service Application, SLHI requests to follow through with the above mentioned disposition, and seeks to dispose of its estimated NBV of its stranded assets as at December 31, 2012.

Table 9-32 provides a summary of the number of meters by rate class that were stranded and smart meters installed as at December 31, 2011.

Table 9-32: Meter count as at December 31, 2011

	A	B	C= B - A	D = C/A
	Stranded Assets	**Smart Meter Installs**	**Variance**	**Variance %**
Residential	2,264	2,309	45	2%
GS < 50 kW	349	397	48	14%

Table 9.33 contains the asset and accumulated depreciation balances as found in the Filing Requirements, Chapter 2 Appendix 2-S.

Table 9.33: Stranded Asset Values

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ 294,462	$ 42,198		$ 252,264		$ 252,264
2007		$ 294,462	$ 53,977		$ 240,485		$ 240,485
2008		$ 294,462	$ 65,755		$ 228,707		$ 228,707
2009		$ 294,462	$ 77,534		$ 216,928		$ 216,928
2010		$ 294,462	$ 89,312		$ 205,150		$ 205,150
2011		$ 294,462	$ 101,091		$ 193,371		$ 193,371
2012	(1)	$ 294,462	$ 112,869		$ 181,593		$ 181,593

SLHI is requesting recovery of the $181,592 in residual net book value of the assets.

With respect to the Filing Requirements Schedule Appendix 2-S, SLHI's responses are as follows:

- SLHI has transferred its stranded meter costs to the "sub-account Stranded Meter Costs" of Account 1555 (Scenario A) in 2012.

- For financial and OEB reporting purposes, the stranded meter assets are recorded in Account 1555 at the NBV, recognizing accumulated depreciation through to 2012 and also recognizing that these meters are still in the rate base and built into distribution rates.

- The forecasted NBV of the stranded meters as at December 31, 2012 is $181,592.

- SLHI notes that carrying charges have not been calculated on the balance above and did not sell and receive any proceeds or contributed capital for stranded meters.

- The number of meters removed is found in the table above, which is compared to the number of smart meter installs provided in EB-2012-0245.

- The number of smart meter installs is higher for both rate classes compared to the number of meters stranded. The reasons for this variance are new services that occurred during the smart meter program (2009 to 2011) and replacement of problematic smart meters in the field.

- SLHI is proposing to recover the stranded meter assets over two years as set out in Table 9-33 and a detailed discussion of the calculation is found below.

As per Guideline *G-2011-0001 Smart Meter Funding and Cost Recover – Final Disposition December 15, 2011* on page 23, SLHI proposes to dispose of the stranded meter costs based on the principles of cost causality and practicality and recovered through a rate rider for the applicable customer classes. The stranded asset balance forecasted as a December 31, 2012 has been allocated between Residential and General Service < 50 kW rate classes by the percentages calculated by the total number of conventional meters disposed of by each respective rate class. SLHI proposes to dispose of the stranded meter cost balance over a 24 month period starting May 1, 2013 and using the 2013 forecasted number of customers to calculate the Stranded Asset Rate Rider (“SMRR”) by rate class. Below is Table 9.34 summarizing the SMRR.

Table 9-34: Rate Rider Calculation

Stranded Meter Costs				
Gross Book Value	$294,462			
Accumulated Depreciation	$112,869			
Net Book Value as at December 31, 2012	$181,592			A
	Residential	**GS < 50 kW**	**Total**	
Number of Customers - 2013 Forecast	2,323	374	2,697	B
Proportion of Stranded NBV $	87%	13%	100%	C
Allocation of NBV to rate classes	$157,985	$23,607	$181,592.00	D = A * C
Proposed Disposition Period	24 months			E
SMRR per month	**$2.83**	**$2.63**		F = D/B/24

GREEN ENERGY PLAN – FUNDING ADDER

SLHI has submitted a basic Green Energy Plan to the OPA and has provided a copy in Exhibit 2, Appendix 2-B. The OPA provided a Letter of Comment which has been provided in Exhibit 2, Appendix 2-C. As part of its plan SLHI did not identify any capital spending requirements. Therefore SLHI is not requesting a funding adder to be included in its rates.

LRAM RECOVERY

Summary

SLHI does not request approval to recover of historical Lost Revenue Adjustment Mechanism ("LRAM") amounts related to Conservation and Demand Management (CDM) activities in 2011 at this time, as explained in Exhibit 4, Tab 1 of this application. The debit balance of $1,252 has been included in Account 1568 of the Deferral and Variance Account file for disposition at a future rate hearing due to immateriality.

Please see Exhibit 4, Tab 1 for additional detail on SLHI's LRAM claim in its 2013 Cost of Service Application.

Appendix 9-A

2013 EDDVAR Continuity Schedule

Deferral/Variance Account Workform for 2013 Filers

Account Descriptions	Account Number	2005									
		Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508					$ -					$ -
Retail Cost Variance Account - Retail	1518					$ -					$ -
Misc. Deferred Debits	1525					$ -					$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548					$ -					$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572					$ -					$ -
Deferred Rate Impact Amounts	1574					$ -					$ -
RSVA - One-time	1582					$ -					$ -
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555					$ -					$ -
Smart Meter OM&A Variance[11]	1556					$ -					$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563					$ -					$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

1A Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

2 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

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

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

5 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

6 If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

7 Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 85).

8 As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

9 The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would have resulted in non-compliance with the timeline set out in section 8 of the SPC regulation.

10 Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cleared as an adjustment to the distributor's revenue requirement.

11 Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the Board's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -			$ 8,647	$ 8,647	$ -			$ 29	$ 29
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ 8,647	$ 8,647	$ -	$ -	$ -	$ 29	$ 29
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ 8,647	$ 8,647	$ -	$ -	$ -	$ 29	$ 29

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ -	$ -	$ -	$ 8,647	$ 8,647	$ -	$ -	$ -	$ 29	$ 29
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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

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

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

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

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

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

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

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

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

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

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

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

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments[3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other[2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other[2]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 8,647	$ 5,185			$ 13,832	$ 29	$ 62			$ 91
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 8,647	$ 5,185	$ -	$ -	$ 13,832	$ 29	$ 62	$ -	$ -	$ 91
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 8,647	$ 5,185	$ -	$ -	$ 13,832	$ 29	$ 62	$ -	$ -	$ 91

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ 8,647	$ 5,185	$ -	$ -	$ 13,832	$ 29	$ 62	$ -	$ -	$ 91
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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

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

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

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

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

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

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

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

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

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

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

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

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 13,832	$ 2,029			$ 15,860	$ 91	$ 21			$ 112
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 13,832	$ 2,029	$ -	$ -	$ 15,860	$ 91	$ 21	$ -	$ -	$ 112
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 13,832	$ 2,029	$ -	$ -	$ 15,860	$ 91	$ 21	$ -	$ -	$ 112

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ 13,832	$ 2,029	$ -	$ -	$ 15,860	$ 91	$ 21	$ -	$ -	$ 112
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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

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

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

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

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

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

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refu

balances in Account 1595 on a memo basis only (line 85).

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

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

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

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

Account Descriptions	Account Number	2009									
		Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$ -			$ 977,314	$ 977,314	$ -			$ 41,474	$ 41,474
RSVA - Wholesale Market Service Charge	1580	$ -			-$ 81,874	-$ 81,874	$ -			$ 17,724	$ 17,724
RSVA - Retail Transmission Network Charge	1584	$ -			-$ 125,277	-$ 125,277	$ -			-$ 7,800	-$ 7,800
RSVA - Retail Transmission Connection Charge	1586	$ -			-$ 1,115,462	-$ 1,115,462	$ -			-$ 93,143	-$ 93,143
RSVA - Power (excluding Global Adjustment)	1588	$ -			-$ 235,509	-$ 235,509	$ -			$ 110,306	$ 110,306
RSVA - Power - Sub-account - Global Adjustment	1588	$ -			$ 395,202	$ 395,202	$ -			$ 16,614	$ 16,614
Recovery of Regulatory Asset Balances	1590	$ -			-$ 288,266	-$ 288,266	$ -			-$ 16,820	-$ 16,820
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -			$ 451,072	$ 451,072	$ -			$ 7,332	$ 7,332
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	-$ 22,800	-$ 22,800	$ -	$ -	$ -	$ 75,687	$ 75,687
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	-$ 418,002	-$ 418,002	$ -	$ -	$ -	$ 59,073	$ 59,073
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ 395,202	$ 395,202	$ -	$ -	$ -	$ 16,614	$ 16,614
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 15,860	-$ 1,002			$ 14,859	$ 112	-$ 3			$ 110
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 15,860	-$ 1,002	$ -	$ -	$ 14,859	$ 112	-$ 3	$ -	$ -	$ 110
Deferred Payments in Lieu of Taxes	1562	$ -			-$ 53,412	-$ 53,412	-$ 4,815	-$ 608			-$ 5,423
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 15,860	-$ 1,002	$ -	-$ 76,212	-$ 61,353	-$ 4,703	-$ 611	$ -	$ 75,687	$ 70,374

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ 15,860	-$ 1,002	$ -	-$ 76,212	-$ 61,353	-$ 4,703	-$ 611	$ -	$ 75,687	$ 70,374
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -			$ 53,412	$ 53,412	$ 4,815	$ 608			$ 5,423
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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

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

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

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

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

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

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

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non-compliance with the timeline set out in section 8 of the SPC regulation.

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

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

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
		2010									
Group 1 Accounts											
LV Variance Account	1550	$ 977,314	$ 44,149	$ 679,586		$ 341,877	$ 41,474	$ 3,946	$ 39,577		$ 5,843
RSVA - Wholesale Market Service Charge	1580	-$ 81,874	-$ 109,755	-$ 7,414		-$ 184,215	$ 17,724	-$ 827	$ 17,745		-$ 848
RSVA - Retail Transmission Network Charge	1584	-$ 125,277	-$ 13,348	-$ 134,839		-$ 3,786	-$ 7,800	-$ 118	-$ 7,424		-$ 494
RSVA - Retail Transmission Connection Charge	1586	-$ 1,115,462	-$ 50,583	-$ 1,109,655		-$ 56,390	-$ 93,143	-$ 2,238	-$ 90,045		-$ 5,336
RSVA - Power (excluding Global Adjustment)	1588	-$ 235,509	-$ 179,716	$ 497,892		-$ 913,117	$ 110,306	-$ 3,577	$ 110,161		-$ 3,432
RSVA - Power - Sub-account - Global Adjustment	1588	$ 395,202	-$ 60,781	$ 206,167		$ 128,254	$ 16,614	$ 1,407	$ 16,038		$ 1,983
Recovery of Regulatory Asset Balances	1590	-$ 288,266		-$ 284,115		-$ 4,151	-$ 16,820	-$ 424	-$ 16,820		-$ 424
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ 451,072	-$ 81,876		-$ 21,866	$ 347,330	$ 7,332	$ 2,593		$ 21,866	$ 31,791
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -	-$ 51,750	$ 153,380		-$ 205,130	$ -	-$ 1,255	-$ 69,232		$ 67,977
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 22,800	-$ 503,660	$ 1,002	-$ 21,866	-$ 549,328	$ 75,687	-$ 493	$ -	$ 21,866	$ 97,060
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 418,002	-$ 442,879	-$ 205,165	-$ 21,866	-$ 677,582	$ 59,073	-$ 1,900	-$ 16,038	$ 21,866	$ 95,077
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 395,202	-$ 60,781	$ 206,167	$ -	$ 128,254	$ 16,614	$ 1,407	$ 16,038	$ -	$ 1,983
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 14,859	-$ 1,607			$ 13,252	$ 110	$ 109			$ 219
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -				$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -				$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -				$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -				$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -				$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -				$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567					$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 14,859	-$ 1,607	$ -	$ -	$ 13,252	$ 110	$ 109	$ -	$ -	$ 219
Deferred Payments in Lieu of Taxes	1562	-$ 53,412				-$ 53,412	-$ 5,423	-$ 426			-$ 5,849
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 61,353	-$ 505,267	$ 1,002	-$ 21,866	-$ 589,488	$ 70,374	-$ 810	$ -	$ 21,866	$ 91,430

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ 29,539			-$ 27,540	$ 1,999		$ 102			$ 102
LRAM Variance Account	**1568**					$ -					$ -
Total including Account 1521 and Account 1568		-$ 31,814	-$ 505,267	$ 1,002	-$ 49,406	-$ 587,489	$ 70,374	-$ 708	$ -	$ 21,866	$ 91,532
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ 53,412				$ 53,412	$ 5,423	$ 426			$ 5,849
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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

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

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

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

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

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

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refu
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non-compliance with the timeline set out in section 8 of the SPC regulation.

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

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

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
		2011												
Group 1 Accounts														
LV Variance Account	1550	$ 341,877	$ 15,524	$ 297,728					$ 59,673	$ 5,843	$ 2,258	$ 6,791		$ 1,310
RSVA - Wholesale Market Service Charge	1580	-$ 184,215	-$ 82,620	-$ 74,462					-$ 192,373	-$ 848	-$ 2,352	-$ 913		-$ 2,287
RSVA - Retail Transmission Network Charge	1584	-$ 3,786	$ 1,331	$ 9,561					-$ 12,016	-$ 494	$ 136	-$ 484		$ 126
RSVA - Retail Transmission Connection Charge	1586	-$ 56,390	-$ 15,737	-$ 5,807					-$ 66,320	-$ 5,336	-$ 897	-$ 5,206		-$ 1,027
RSVA - Power (excluding Global Adjustment)	1588	-$ 913,117	$ 40,127	-$ 733,400					-$ 139,590	-$ 3,432	-$ 2,393	-$ 7,386		$ 1,561
RSVA - Power - Sub-account - Global Adjustment	1588	$ 128,254	-$ 69,209	$ 189,035					-$ 129,990	$ 1,983	$ 468	$ 3,217		-$ 766
Recovery of Regulatory Asset Balances	1590	-$ 4,151		-$ 4,152					$ 1	-$ 424		-$ 437		$ 13
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ 347,330	-$ 44,366						$ 302,964	$ 31,791	$ 4,558			$ 36,349
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -							$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$ 205,130	-$ 8,678						-$ 213,808	$ 67,977	-$ 3,145			$ 64,832
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 549,328	-$ 163,627	-$ 321,497	$ -	$ -	$ -	$ -	-$ 391,458	$ 97,060	-$ 1,368	-$ 4,418	$ -	$ 100,110
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 677,582	-$ 94,418	-$ 510,532	$ -	$ -	$ -	$ -	-$ 261,468	$ 95,077	-$ 1,836	-$ 7,635	$ -	$ 100,876
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 128,254	-$ 69,209	$ 189,035	$ -	$ -	$ -	$ -	-$ 129,990	$ 1,983	$ 468	$ 3,217	$ -	-$ 766
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	$ 17,500						$ 17,500	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -							$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 13,252	-$ 1,552						$ 11,700	$ 219	$ 168			$ 387
Misc. Deferred Debits	1525	$ -							$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -							$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -							$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -							$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -							$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -							$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -							$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -							$ -	$ -				$ -
Board-Approved CDM Variance Account	1567	$ -							$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -							$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -							$ -	$ -				$ -
RSVA - One-time	1582	$ -							$ -	$ -				$ -
Other Deferred Credits	2425	$ -							$ -	$ -				$ -
Group 2 Sub-Total		$ 13,252	$ 15,948	$ -	$ -	$ -	$ -	$ -	$ 29,200	$ 219	$ 168	$ -	$ -	$ 387
Deferred Payments in Lieu of Taxes	1562	-$ 53,412						-$ 61,915	-$ 115,327	-$ 5,849			-$ 22,285	-$ 28,134
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -	-$ 6,373						-$ 6,373	$ -	-$ 71			-$ 71
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 589,488	-$ 154,052	-$ 321,497	$ -	$ -	$ -	-$ 61,915	-$ 483,958	$ 91,430	-$ 1,271	-$ 4,418	-$ 22,285	$ 72,292

		2011												
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ 1,999							$ 1,999	$ 102	$ 65			$ 167
LRAM Variance Account	**1568**	$ -							$ -	$ -				$ -
Total including Account 1521 and Account 1568		-$ 587,489	-$ 154,052	-$ 321,497	$ -	$ -	$ -	-$ 61,915	-$ 481,959	$ 91,532	-$ 1,206	-$ 4,418	-$ 22,285	$ 72,458
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -							$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -							$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -							$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -							$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account [5]	1563	$ 53,412						$ 61,915	$ 115,327	$ 5,849			$ 22,285	$ 28,134
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -	$ 12,745						$ 12,745	$ -	$ 141			$ 141
Disposition and Recovery of Regulatory Balances[7]	1595	$ -	$ 73,545	$ 323,486					-$ 249,941	$ -	-$ 3,220	$ 4,418		-$ 7,638

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

Account Descriptions	Account Number	2012				Projected Interest on Dec-31-11 Balances			2.1.7 RRR	
		Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550	$ 44,149	-$ 83	$ 15,524	$ 1,393	$ 228	$ 76	$ 17,221	$ 60,982	-$ 1
RSVA - Wholesale Market Service Charge	1580	-$ 109,753	-$ 2,086	-$ 82,620	-$ 201	-$ 1,215	-$ 405	-$ 84,441	-$ 194,661	-$ 1
RSVA - Retail Transmission Network Charge	1584	-$ 13,347	-$ 272	$ 1,331	$ 398	$ 20	$ 7	$ 1,755	-$ 11,891	-$ 1
RSVA - Retail Transmission Connection Charge	1586	-$ 50,583	-$ 1,121	-$ 15,737	$ 94	-$ 231	-$ 77	-$ 15,952	-$ 67,347	$ 1
RSVA - Power (excluding Global Adjustment)	1588	-$ 179,717	$ 432	$ 40,127	$ 1,129	$ 590	$ 197	$ 42,042	-$ 138,029	$ 0
RSVA - Power - Sub-account - Global Adjustment	1588	-$ 60,781	-$ 2,425	-$ 69,209	$ 1,659	-$ 1,017	-$ 339	-$ 68,906	-$ 130,755	$ 0
Recovery of Regulatory Asset Balances	1590	$ 1	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	-$ 14
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ 347,330	$ 38,599	-$ 44,366	-$ 2,250	-$ 652	-$ 217	-$ 47,485	$ 339,313	-$ 0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$ -	$ -	$ -	$ -	$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			-$ 213,808	$ 64,832	-$ 3,143	-$ 1,048	-$ 153,167	-$ 148,976	$ 0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 22,701	$ 33,057	-$ 368,757	$ 67,053	-$ 5,421	-$ 1,807	-$ 308,932	-$ 291,363	-$ 15
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 38,080	$ 35,482	-$ 299,548	$ 65,394	-$ 4,403	-$ 1,468	-$ 240,026	-$ 160,608	-$ 15
RSVA - Power - Sub-account - Global Adjustment	**1588**	-$ 60,781	-$ 2,425	-$ 69,209	$ 1,659	-$ 1,017	-$ 339	-$ 68,906	-$ 130,755	$ 0
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$ 17,500	$ -	$ 257	$ 86	$ 17,843	$ 17,500	$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508			$ -	$ -			$ -		$ -
Retail Cost Variance Account - Retail	1518			$ 11,700	$ 387	$ 172	$ 57	$ 12,316	$ 12,086	-$ 0
Misc. Deferred Debits	1525			$ -	$ -			$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531			$ -	$ -			$ -		$ -
Renewable Generation Connection OM&A Deferral Account	1532			$ -	$ -			$ -		$ -
Renewable Generation Connection Funding Adder Deferral Account	1533			$ -	$ -			$ -		$ -
Smart Grid Capital Deferral Account	1534			$ -	$ -			$ -		$ -
Smart Grid OM&A Deferral Account	1535			$ -	$ -			$ -		$ -
Smart Grid Funding Adder Deferral Account	1536			$ -	$ -			$ -		$ -
Retail Cost Variance Account - STR	1548			$ -	$ -			$ -		$ -
Board-Approved CDM Variance Account	1567			$ -	$ -			$ -		$ -
Extra-Ordinary Event Costs	1572			$ -	$ -			$ -		$ -
Deferred Rate Impact Amounts	1574			$ -	$ -			$ -		$ -
RSVA - One-time	1582			$ -	$ -			$ -		$ -
Other Deferred Credits	2425			$ -	$ -			$ -		$ -
Group 2 Sub-Total		$ -	$ -	$ 29,200	$ 387	$ 429	$ 143	$ 30,159	$ 29,586	-$ 0
Deferred Payments in Lieu of Taxes	1562	-$ 115,327	-$ 28,134	$ -	$ -			$ -	-$ 48,948	$ 94,513
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			-$ 6,373	-$ 71	-$ 94	-$ 32	-$ 6,568	-$ 12,886	-$ 6,443
										$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 138,028	$ 4,923	-$ 345,930	$ 67,369	-$ 5,085	-$ 1,695	-$ 285,341	-$ 323,611	$ 88,055

Account Descriptions	Account Number	2012 Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ 1,999	$ 174	$ 0	-$ 7	$ 7		$ 0	$ 2,165	-$ 0
										$ -
LRAM Variance Account	**1568**			$ -	$ -			$ -		$ -
Total including Account 1521 and Account 1568		-$ 136,029	$ 5,097	-$ 345,930	$ 67,362	-$ 5,078	-$ 1,695	-$ 285,341	-$ 321,446	$ 88,055
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555			$ -	$ -			$ -		$ -
Smart Meter OM&A Variance[11]	1556			$ -	$ -			$ -		$ -
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563			$ 115,327	$ 28,134			$ 143,461	$ 48,948	-$ 94,513
IFRS-CGAAP Transition PP&E Amounts[10]	1575			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$ 12,745	$ 141	$ 187	$ 63	$ 13,136	$ 12,886	$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ 227,831	-$ 97,013	-$ 477,772	$ 89,375	-$ 7,023	-$ 2,341	-$ 397,761	-$ 257,579	$ -

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